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BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

IN RE: APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)	CASE NO. 2009-00548
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	)	CASE NO. 2009-00549

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

April 2010

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KENTUCKY PUBLIC SERVICE COMMISSION

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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. Please state your occupation and employer.

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practice license, and a Certified Management Accountant ("CMA").

I have been an active participant in the utility industry for more than thirty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on planning, ratemaking, accounting, finance, and tax issues in proceedings before regulatory commissions and courts at the federal and state levels on nearly two hundred occasions, including numerous proceedings before the Kentucky Public Service Commission involving Kentucky Utilities Company ("KU"), Louisville Gas and Electric Company ("LG&E"), Kentucky Power Company, East Kentucky Power Company and Big Rivers Electric Corporation. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group of large customers taking electric service at retail from KU and LG&E (also referred to individually as "Company" or collectively as "Companies").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize the KIUC revenue requirement recommendations, to address specific issues that affect each Company's revenue requirement and to quantify the effects of the return on equity recommendation sponsored by KIUC witness Mr. Richard Baudino.

Q. Please summarize your testimony.

A. I recommend that the Commission increase KU's base rates by no more than $47.565 million, a reduction of at least $87.721 million compared to its requested increase of $135.285 million. I recommend that the Commission increase LG&E's base rates by no more than $26.977 million, a reduction of at least $67.997 million compared to its requested increase of $94.973 million.

The following table lists each KIUC adjustment and the effect on each Company's claimed revenue deficiency, which include the adjustments I address and the effect of the return on common equity recommendation sponsored by KIUC witness Mr. Richard Baudino.

Louisville Gas and Electric Company and Kentucky Utilities Company
Summary of Revenue Requirement Adjustments-Jurisdictional Electric Operations
Recommended by KIUC
For the Test Year Ended October 31, 2009
($ Millions)

	KU	LG&E
Increase Requested by Company	135.285	94.973
KIUC Adjustments:		
Operating Income Issues		
Reject Company's Proforma Adjustment to Remove Unbilled Revenues	(3.745)	(2.871)
Correct Off-System Sales Revenue Adjustment for ECR	(0.639)	(0.168)
Normalize Off-System Sales Revenues	(9.987)	(22.717)
Include KU Share of EEI Earnings	(2.488)	-
Normalize KU Share of EEI Earnings	(16.722)	-
Eliminate CCS One-Time Impementation Expense	(1.348)	(1.443)
Update Pension and OPEB Expense	(0.522)	(1.688)
Reject Elimination of Kentucky Coal Tax Credit Through Property Taxes	(4.032)	(2.637)
Correct Error in Trimble County 2 Advanced Coal ITC Permanent Difference	(0.444)	(0.104)
Cost of Capital Issues		
Reflect Average Short Term Debt	(1.567)	(9.344)
Reflect Short Term Debt Rate of 0.2% and Long Term Debt Rate of 4.58%	(0.285)	(0.256)
Reflect Return on Equity of 9.7%	(46.895)	(26.769)
Eliminate EEI Reductions to Capitalization	0.954	-
Total KIUC Adjustments to Companies' Corrected Requests	(87.721)	(67.997)
KIUC Recommended Reductions from Present Base Rates	47.565	26.977

I have structured my testimony into two additional sections consistent with the categories of issues on the preceding table and address each issue in the sequence listed on the preceding table. The amounts cited throughout my testimony are electric jurisdictional amounts unless otherwise indicated.

II. OPERATING INCOME ISSUES

Unbilled Revenues Should Not Be Eliminated

Q. Please describe the Companies' adjustments to remove unbilled revenues for ratemaking purposes.

A. KU and LG&E propose reductions to their test year electric operating revenues of $3.745 million $2.871 million, respectively, to remove unbilled revenues from their per books revenues for ratemaking purposes. These adjustments convert their revenue accounting from the unbilled revenues methodology actually used for accounting purposes to a meters read methodology that is not used for that purpose.

Q. Please describe the difference between the unbilled revenues and meters read methodologies for recognizing revenues.

A. The Companies actually recognize (accrue) revenues on their accounting books using the unbilled revenues methodology, not the meters read methodology. The unbilled revenues methodology matches the revenues in the month with the service provided (electricity delivered) and the costs incurred to provide that service. In contrast, the meters read methodology only recognizes (accrues) revenues when the meters and ratepayers are billed; however, this process occurs as much as a month after service was provided (an average of half a month). Thus, the meters read methodology introduces a lag of approximately a half a month in the recognition of revenues after service was provided.

Q. The Companies proposed a similar adjustment in Case Nos. 2003-00433 and 2003-00434 and again in Case Nos. 2008-00251, and 2008-00252. What was the resolution of the issue in those proceedings?

A. The Commission did not adjudicate the unbilled revenues issue as a contested issue in any of those proceedings. KIUC opposed this unbilled revenues adjustment in Case Nos. 2003-00433 and 2003-00434, but the KIUC testimony was withdrawn in conjunction with the settlement of the revenue requirement issues between the Companies and KIUC. In response to the Attorney General's opposition to the settlement, the Commission found that certain of the adjustments in the Companies' filings, including the unbilled revenues adjustment in those cases, were "reasonable;" however, there was no record opposition to those adjustments due to the withdrawal of KIUC's testimony. In none of the cases did the settlements address or adopt the Companies' adjustment to eliminate unbilled revenues and the parties to the settlements, including KIUC, reserved their rights to adjudicate the issues in the case in the future.

The Attorney General opposed the settlement in Case Nos. 2003-00433 and 2003-00434, but did not argue either for or against the adjustment to eliminate unbilled revenues. The Attorney General argued only that the Commission should adjust expense levels to correspond to the unbilled revenues adjustment. The Commission rejected the Attorney General's proposal.

Q. Should the Commission accept the Company's adjustment to restate its per books accounting revenues and utilize the meters read methodology for ratemaking purposes?

A. No. There is no principled basis to accept this adjustment. The Companies do not use the meters read methodology for accounting purposes and the Commission should not use it for ratemaking purposes. The primary reason that the unbilled revenues methodology is used for accounting purposes is that it *matches* the revenues earned and expenses incurred each month. Under the unbilled revenues accounting, the revenues are earned and recognized when the Companies provide service, not when the meters are read. At the same time, all the expenses to provide service also are recognized on an accrual basis when the Companies provide service, not in some subsequent month when the Companies actually pay those expenses. Thus, the Companies' accounting itself ensures that there is a proper *matching* between the revenues earned and the expenses incurred to generate those revenues. There is no reason to accept an adjustment for ratemaking that disturbs this *matching* properly recognized for accounting purposes.

In contrast to the conceptual soundness of the unbilled revenue methodology for both accounting purposes and ratemaking purposes, the meters read methodology results in a *mismatch* of revenues and expenses by redefining the test year and thereby shifting revenues in and out of the actual test year. This occurs because revenues in any one month are based on meter reads for service partially provided in the prior month. Thus, if the meters read methodology is adopted for ratemaking purposes, the revenues are not measured based on service provided during the test year, but rather for a different twelve month period extending from the approximate midpoint of the month preceding the test year through the approximate midpoint of the last month of the test year.

Thus, the Companies' proposal to use the meters read methodology for ratemaking purposes creates an unjustified *mismatch* in the test year between revenues and expenses by improperly redefining the test year for revenues. The unbilled revenues methodology provides the best *matching* between revenues and expense and preserves the definition of the test year for the revenue component of the ratemaking formula.

Off-System Sales Revenue Adjustment For ECR Is Improperly Calculated

Q. Please describe the Companies' adjustments to reduce off-system sales revenues for the portion of the ECR revenue requirement allocated to off-system sales.

A. KU proposes an adjustment to reduce OSS revenues by $3.723 million and LG&E proposes an adjustment to reduce OSS revenues by $2.034 million. The computations for each Company are detailed on Mr. Rives' Exhibit 1 Schedule 1.07. To compute the amount of the reduction, the Companies computed an annualized simple average of the test year monthly ECR factors (percentages) and then multiplied this annualized simple average percentage times the total test year OSS revenues to compute the reduction for the ECR environmental costs allocated to off-system sales.

Q. Are the computations mathematically correct?

A. No. The Companies should have used a weighted average percentage instead of a simple average percentage. The OSS revenues and the ECR factors vary considerably each month. Computing a simple average of these factors does not properly capture the monthly variations and overstates the average ECR factor used to compute the ECR revenue requirement allocated to and thus, the reduction to the OSS revenues.

Q. Have the Companies provided corrected computations using a weighted average of the monthly ECR factors?

A. Yes. KU provided corrected computations in response to Staff 2-29(c). The corrected computations result in a reduction to OSS revenues of $3.084 million compared to the KU's computation of $3.723 million in its filing. Consequently, the correction reduces the KU revenue requirement by $0.639 million. I have attached a copy of the KU response to Staff 2-29(c) as my Exhibit___(LK-2).

LG&E provided corrected computation in response to Staff 2-33(c). The corrected computations result in a reduction to OSS revenues of $1.866 million compared to the LG&E's computation of $2.034 million in its filing. Consequently, the correction reduces the LG&E revenue requirement by $0.168 million. I have attached a copy of the LG&E response to Staff 2-33(c) as my Exhibit___(LK-3).

Q. Is there another error reflected in the Companies' adjustments to reduce off-system sales revenues for the portion of the ECR revenue requirement allocated to off-system sales?

A. Yes. The Companies' failed to reduce their adjustments to reflect the rate increases that are authorized in these proceedings. To the extent there are rate increases in these proceedings, retail revenues will increase, the percentage of retail revenues to total revenues will increase and the percentage of off-system sales revenues to total revenues will decrease, assuming that the off-system sales revenues (or margins) are not adjusted from test year levels. If the Commission normalizes off-system sales margins as I propose, this may result in an increase in the adjustment if normalized off-system sales revenues, in addition to off-system sales margins, can be separately quantified for purposes of this adjustment.

Q. Have you quantified the effect of correcting this error?

A. No. The effect is dependent upon the Commission's decisions in this proceeding on all revenue requirement issues, but should be incorporated as one of the final, if not the final, adjustment in the computation of the Companies' revenue deficiencies.

<u>Off-System Sales Margins Should Be Normalized</u>

Q. Have the Companies normalized their profits from off-system sales?

A. No.

Q. Were the Companies' off-system sales margins normal in the test year?

A. No. The Companies' off-system sales margins hit historic lows during the test year compared to prior years. I have summarized the Companies' OSS margins for the last five years on the following table:

Kentucky Utilities Company and Louisville Gas and Electric Company
History of Off-System Sales Revenues and Margins
($)

	Intersystem Off-System Sales Revenues Monthly ECR Filings	Off-System Sales Cost of Fuel Monthly Fuel Filings	Off-System Sales Margins
Kentucky Utilities Company			
Twelve Months Ended 12-31-2005	128,185,637	95,156,288	33,029,349
Twelve Months Ended 12-31-2006	85,421,897	65,809,314	19,612,583
Twelve Months Ended 12-31-2007	50,719,786	40,752,971	9,966,815
Twelve Months Ended 12-31-2008	96,723,316	83,791,493	12,931,823
Twelve Months Ended 10-31-2009	45,113,208	40,629,402	4,483,806
Louisville Gas and Electric Company			
Twelve Months Ended 12-31-2005	259,612,909	191,833,293	67,779,616
Twelve Months Ended 12-31-2006	207,530,954	167,326,722	40,204,232
Twelve Months Ended 12-31-2007	163,023,282	134,076,606	28,946,676
Twelve Months Ended 12-31-2008	238,629,677	189,093,281	49,536,396
Twelve Months Ended 10-31-2009	169,469,043	151,248,885	18,220,158

Q. What factors affect the OSS margins?

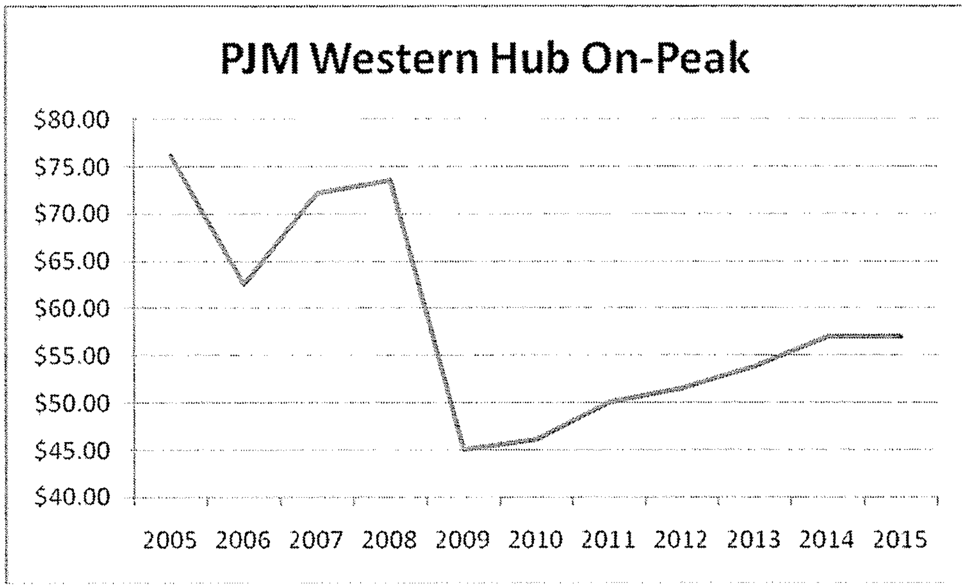
A. There are three primary factors: wholesale market prices, volume of sales, and cost of sales. The OSS revenues are determined by the wholesale market prices at the time of sale times the volume of sales in those hours. The OSS margins are the OSS revenues less cost of sales. Thus, if wholesale market prices are at a low-point, then OSS revenues and margins also will be at a low-point, all else equal.

Q. Does the generation available to the Companies also affect OSS margins?

A. Yes. The more generation, the more OSS margins, assuming that the cost to generate and deliver is less than the market prices available, all else equal. The level of generation is an important consideration in the amount of OSS margins that should be included for the test year. The Companies have proposed that ratepayers pay for the depreciation of and the return on the new Trimble County 2 unit in rates that will be effective in this proceeding, but the Companies have not proposed an adjustment to increase OSS margins resulting from the additional energy that will be available for sale.

Q. Were wholesale market prices also at a low-point during the test year?

A. Yes. Wholesale market prices are measured at various delivery points, such as the PJM Western Hub and the MISO Into Cinergy hub. Historic data is available from the Intercontinental Exchange ("ICE") and forward information is available from CME Group, at least for the PJM Western Hub. The following chart provides the PJM Western Hub average actual annual on-peak prices for the years 2005 through 2009 and the forward average annual on-peak prices for the years 2010 through 2015.



Q. Why is the fact that OSS margins are at a low-point significant in quantifying the base revenue requirements in these proceedings?

A. Although the Companies' OSS margins are significant and volatile, the Commission's historic practice for KU and LG&E has been to include these margins in base rates rather than crediting them through some other mechanism. Test year disparities in this case compared to normalized levels will be embedded in base rates until base rates are reset again. If the OSS margins are not normalized, then ratepayers will be harmed (and the Companies improperly enriched) until base rates are reset in the next base rate proceeding. Thus, it is vitally important that base rates reflect a normal amount of OSS margins or that the Commission adopt an alternative recovery method that allows ratepayers and the Companies to share in the increases or reductions from the amounts included in base rates.

Q. Have the Companies normalized other revenues and expenses?

A. Yes. The Companies included adjustments to weather/temperature normalize retail revenues and expenses, normalize storm damage expense, and normalize injuries and damages expense, among others.

Q. Is the normalization of OSS margins consistent with the normalization of retail revenues and various expenses reflected in the Companies' filings?

A. Yes. Normalization adjustments are made when there are demonstrably anomalous revenue or expense levels and the revenues or expenses can vary significantly due to circumstances largely outside the control of the utility. The adjustments necessary to normalize each of these revenue and expense adjustments is based on historic data that is averaged to determine the "normal" and restate the actual test year amounts to a normalized and ongoing level for ratemaking purposes. For example, the Companies' proposed weather/temperature normalization of revenues is based on "normal" temperatures over a 30 year period. The Companies' proposed normalization of storm damage expense removes the expenses incurred for severe storms for deferral and amortization and averages the remaining less-severe storm expenses over an approximate 10 year period. The Companies' proposed normalization of injuries and damages expense averages these expenses over an approximate 10 year period.

Q. Do the Companies agree that normalization adjustments are necessary and appropriate so that revenues and expenses will be representative on a going-forward basis?

A. Yes. This is the principle underlying the Companies' adjustments to weather/normalize retail revenues and numerous other normalization adjustments to revenues and expenses. Company witness Mr. Seelye stated this principle on page 41 of his Direct Testimony as follows:

> **The underlying principle is that when rates go into effect as a result of a general rate case, those rates will represent a level of revenue that will allow the utility to recover its reasonably incurred costs on a going-forward basis. This principle holds regardless of whether a projected test year or a historical test year is used to set rates. When rates are based on a historical test year, pro-forma adjustments are made to test-year operating results so that revenues and expenses will be representative on a going-forward basis. This is the principle behind adjusting certain test-year operating results to reflect a going-forward level of expenses and revenues for things such as storm damage expenses, injuries and damages, and year-end levels of customers . . . or annualizing other revenues and expenses (e.g., depreciation expense and wages and benefits expense) to reflect the full amount on a going forward basis.**

Q. Did the Commission adopt an alternative recovery mechanism for Kentucky Power Company to address volatility in the OSS margins?

A. Yes. The Commission adopted a System Sales Clause ("SSC") for Kentucky Power Company and its ratepayers in conjunction with a settlement of a base rate case many years ago. The SSC effectively operates to normalize OSS margins on an ongoing basis by providing a sharing of the margins above or below certain threshold amounts that are embedded in base rates.

Q. Do you recommend that the Commission adopt an SSC in these proceedings?

A. KIUC does not believe the Commission can impose an SSC on the parties absent specific statutory authorization, but the parties could agree to an acceptable version of such a recovery mechanism.

Q. Have you quantified the effect of your recommendation to normalize the OSS margins?

A. Yes. The effect is to reduce the KU revenue requirement by $9.987 million and the LG&E revenue requirement by $22.717 million. I computed the average of the OSS margins for calendar years 2005 through 2008 and the test year. I obtained the OSS revenues from the Companies' monthly environmental surcharge filings and the fuel costs from the Companies' monthly fuel adjustment clause filings. The computations are detailed on my Exhibit___(LK-4).

EEI Earnings Should be Incorporated in Revenue Requirement (KU Only)

Q. Please describe the KU investment in Electric Energy, Inc. ("EEI").

A. KU and several other utilities invested in EEI in the early 1950s. EEI was formed to own, build and operate an electric generating facility in Joppa, Illinois to supply power to the United States Atomic Energy Commission. Excess power was sold to the sponsoring utilities, including KU, pursuant to cost-based contracts, through 2005. The gross capacity of the plant currently is 1,162 mW, consisting of a 1,086 mW coal-fired plant and 76 mW in combustion turbine capacity.

KU owns 20% of EEI. Other utilities, all of which are now owned by Ameren, own the other 80% of EEI. KU is entitled to 20% of the EEI earnings and 20% of the EEI dividends. Prior to January 1, 2006, KU was entitled to 20% of the EEI capacity and energy pursuant to cost-based contracts, which included the return of and on its 20% share of the EEI rate base.

KU recognizes its share of the EEI earnings using the equity method of accounting. It recognizes its share of the EEI earnings below the line in account 418.1, Equity in Earnings of Subsidiary Companies, although EEI is not a KU subsidiary. The KU share of EEI earnings each year is added to KU's account 216.1, Unappropriated Undistributed Subsidiary Earnings. The KU share of EEI dividends is then used to reduce the amount in account 216.1 and to increase KU's account 216, Unappropriated Retained Earnings. The EEI dividends have no effect on KU's common equity capitalization; the dividends only affect which common equity account the cumulative EEI earnings are reported. KU provided a description of its ownership and accounting for its share of EEI in response to KIUC 1-40, 1-61 and 1-62. I have attached a copy of each of these responses as my Exhibit___(LK-5), Exhibit___(LK-6), and Exhibit___(LK-7), respectively.

Q. Please describe how the Commission historically reflected the purchased power expense and EEI investment in KU's revenue requirement.

A. The Commission historically provided the Company recovery of the purchased power expense pursuant to its cost-based contract with EEI through a combination of base rates and the fuel adjustment clause. In this manner, the Commission provided KU a return of and on its rate base investment in EEI through the purchased power expense recovered through base rates. To avoid a double recovery of these costs already included in purchased power expense, the Commission did not include KU's share of EEI earnings or its EEI investment in the revenue requirement.

Q. Please describe the change in circumstances that occurred on January 1, 2006.

A. KU discontinued purchasing cost-based power from EEI on January 1, 2006. Companies witness Mr. Thompson describes this change in his Direct Testimony at page 8 in this proceeding as follows:

> **[T]he available supply has decreased as KU no longer purchases energy from Electric Energy, Inc. ("EE Inc"). In 2006, KU's power supply agreement with EE Inc expired under its own terms and the majority owners of EE Inc, over KU's objection, elected to pursue market-based pricing authority. Under a long-standing agreement, KU had been purchasing 200 MW of relatively low-cost base load energy, the equivalent of approximately 1,450 GWh of energy each year.**

Q. What were the results of this change on KU's costs and its earnings?

A. Since January 1, 2006, KU's fuel and purchased power costs have increased compared to the "relatively low cost-based capacity and energy" obtained through the cost-based contract with EEI. KU now must generate or purchase at higher cost or sell less energy off-system than if the cost-based capacity and energy had remained available. The reductions in energy available have reduced the off-system sales margins that otherwise would be used to reduce KU's base revenue requirement. In addition to this increase in the base revenue requirement, the loss of this low-cost energy has compounded the harm to ratepayers through the fuel adjustment clause.

At the same time that the costs to ratepayers increased, KU's share of EEI earnings increased; however, KU retained the EEI earnings for its shareholder and reported the earnings below the line, while the increased costs were recovered from ratepayers. Prior to 2006, KU's share of EEI earnings was relatively minor, primarily due to the fact that most of EEI's power was sold pursuant to cost-based contracts to its owners and only the excess was sold into the wholesale market. However, after 2005, KU's share of EEI earnings increased dramatically through 2008. EEI's earnings then declined in the test year due to the effects of the recession on the wholesale power market. KU's share of EEI earnings on a before tax basis was $29.406 million in 2006, $26.359 million in 2007, $29.549 million in 2008, and $2.855 million in the test year, according to KU's response to KIUC 1-61(f). If the wholesale power market recovers as the forward price curves suggest they will, then KU's share of EEI earnings will increase from the low-point test year amounts.

Q. Has KU changed the methodology used in its filing to reflect the change in circumstances since the end of 2005 when the EEI cost-based contract was terminated?

A. No. The Company's failure to change the methodology to reflect the change in circumstances improperly and artificially increased its claimed revenue requirement. KU excluded the EEI earnings from the revenue requirement. In addition, KU reduced its capitalization by $1.295 million, the amount of its original investment in EEI through prorata reductions to all capitalization components, and reduced account 216 Undistributed Subsidiary Earnings by $6.207 million. However, these adjustments no longer are appropriate. There no longer is a need to avoid double counting the EEI earnings and investment in the revenue requirement because KU no longer incurs the EEI cost-based purchased power expense.

Q. Now that the cost-based contract has terminated, should the Commission continue to make the adjustments that were necessary in the past to avoid double counting the cost of the contract when it was in effect?

A. No. The Commission should reassess these adjustments given the change in circumstances. Although KIUC addressed this issue in Case No. 2008-00341, the case was settled without any adjudication of this issue.

Q. How should the Commission proceed on this issue?

A. I recommend that the Commission incorporate KU's share of EEI earnings as a reduction to the Company's revenue requirement and include KU's EEI investment in its capitalization. This will reflect the facts as they exist now that the contract with EEI has been terminated and there no longer is any need to avoid a double recovery of the Company's costs. First, KU is the entity that owns the 20% share of EEI, not some subsidiary of KU or any other affiliated entity. KU's investment in EEI is recorded in account 123, Investment in Associated Companies. The investment is a "utility" investment, not a "non-utility" investment. Thus, KU's share of the EEI earnings and investment in EEI should be included in operating income and capitalization unless it is necessary, as it was in the past, to exclude the earnings and investment to avoid double counting the related cost for ratemaking purposes.

Second, the effects of losing the "relatively low cost-based capacity and energy" obtained through the cost-based contract with EEI already are being recovered and will continue to be recovered by KU through base rates and the fuel adjustment clause. KU's share of the EEI earnings should be used to defray these increased costs going forward.

In short, the Commission's historic practice of excluding the EEI earnings and capitalization from the Company's revenue requirement no longer is appropriate. These amounts now should be included due to the change in circumstances since the Company's last base rate case.

Q. How should the Commission incorporate the EEI earnings and capitalization in the revenue requirement?

A. First, the Commission should incorporate KU's share of the EEI earnings before tax as a reduction to the revenue requirement. Second, the Commission should eliminate all adjustments to reduce the KU capitalization for the EEI investment. In this manner, the Company's operating income will be increased to include the EEI earnings and KU's capitalization no longer will be reduced to exclude the EEI investment for ratemaking purposes.

Q. Have you quantified the effect on KU's revenue requirement of incorporating the EEI earnings and capitalization?

A. Yes. The effect is to reduce KU's revenue requirement by $1.515 million. This is the net effect of a reduction of $2.488 million in the revenue requirement for the test year EEI earnings before tax offset in part by an increase of $0.973 million to eliminate all of the Company's adjustments to capitalization for the EEI investment shown on the Company's revised Exhibit 2. To quantify the effect of eliminating the Company's adjustments to capitalization, I recomputed the weighted average cost of capital and then multiplied this change in the weighted cost of capital times the increase in capitalization. The computations are detailed on my Exhibit___(LK-8).

<u>EEI Earnings Should Be Normalized (KU Only)</u>

Q. In addition to including the EEI earnings, should the Commission normalize the test year EEI earnings?

A. Yes. The test year EEI earnings were at a low-point compared to the prior years. The EEI earnings should reflect the normalized level represented in the calendar years 2006-2008 and the test year, similar to my recommendation to normalize OSS margins and similar to the Companies' numerous normalization adjustments relying on averaging techniques, such as those used for storm damage expense and injuries and damages expense. Similar to the OSS margins, the EEI margins are significant and volatile. It would not be appropriate to use the low-point for the EEI earnings in the test year as a representative and going-forward level.

Q. Have you quantified the effect of your recommendation?

A. Yes. The effect is to increase the EEI earnings by an additional $16.722 million on a before tax basis and to reduce the revenue requirement by an equivalent amount. I quantified this normalization adjustment by computing the average of the EEI earnings amounts on a before tax basis for the 2006, 2007, and 2008 calendar years and the test year and then subtracting the test year amount. These computations are detailed on my Exhibit___(LK-9).

<u>CCS One-Time Implementation Expense Should Be Eliminated</u>

Q. When the Companies replaced their mainframe application with a new Customer Care System, did they incur one-time implementation expenses in the test year?

A. Yes. KU incurred one-time implementation expenses of $1.349 million (total Company less amounts charged below the line) during the test year, according to its response to KIUC 1-44. LG&E incurred one-time implementation expenses of $1.443 million (total electric and gas less amounts charged below the line) during the test year, according to its response to KIUC 1-42. I have attached a copy of the KU response to KIUC 1-44 as my Exhibit___(LK-10) and the LG&E response to KIUC 1-42 as my Exhibit___(LK-11).

Q. Should the Commission include these one-time expenses in the revenue requirement?

A. No. These amounts were incurred to implement the CCS and are not recurring expenses, a fact that was acknowledged by KU in response to KIUC 1-44 and by LG&E in response to KIUC 1-42. These expenses are more akin to capital costs because they were incurred to install the CCS and were not incurred to operate the CCS on an ongoing basis. As an alternative to simply removing these expenses from the test year, the Commission could direct that they be added to the capital costs of the CCS.

<u>Pension and OPEB Expense Should Be Updated</u>

Q. Have the Companies updated their pension, other post retirement benefits ("OPEB") and other post employment benefits expenses since they made their filings?

A. Yes. The Companies have revised their expenses based on the results of the 2010 Mercer Study. The Companies included annualization adjustments for these expenses in their filings based on a preliminary 2010 Mercer Study. Based on the Companies' revisions, KU's expenses should be reduced by $0.522 million and LG&E's by $1.688 million.

KU included $20.476 million ($22.956 million times 89.197% jurisdictional factor from Exhibit 1 Schedule 1.17) in its filing. This amount should be reduced to $19.954 million ($22.371 million from response to Staff 2-40 times 89.197% jurisdictional factor).

LG&E included $24.383 million ($30.479 million total Company times 80% electric allocation from Exhibit 1 Schedule 1.17) in its filing. This amount should be reduced to $22.695 million ($28.369 million from response to Staff 2-40 times 80% electric allocation).

<u>Kentucky Coal Tax Credit Should Not Be Eliminated</u>

Q. Please describe the Companies' proposal to remove the Kentucky coal tax credit from income tax and property tax expenses.

A. The Companies propose to remove this tax credit from their property tax expense for ratemaking purposes, although the Companies will continue to be eligible for these credits through 2010. KU proposes to remove $1.644 million from income tax expense ($1.681 million total Company times 97.803% jurisdictional allocation from Exhibit 1 Schedule 1.43) and $1.415 million from property tax expense ($1.612 million total Company times 87.792% jurisdictional allocation from Exhibit 1 Schedule 1.38). The KU adjustments have the effect of increasing its revenue requirement by $4.032 million ($1.644 million increase in income tax expense divided by 0.6281 gross up factor plus $1.415 million increase in property tax expense).

LG&E proposes to remove $1.038 million from income tax expense (Exhibit 1 Schedule 1.43) and $0.977 million from property tax expense (Exhibit 1 Schedule 1.38). The LG&E adjustments have the effect of increasing its revenue requirement by $2.637 million ($1.038 million increase in income tax expense divided by 0.6252 gross-up factor plus $0.977 increase in property tax expense).

Q. How do the Companies record the Kentucky coal tax credits for accounting purposes?

A. The Companies record these credits in the year after the coal purchases are made. The credit applicable to the coal purchases in 2009 will not be recorded on the Companies' accounting books until 2010. The credit is first applied against the state income tax expense and if it cannot be fully utilized in that manner, is then applied to the property tax expense. To the extent the credit is applied to income tax expense, the revenue requirement effect would be the expense amount grossed-up for income taxes. To the extent the credit is applied to property tax expense, there would be no gross-up for income taxes. In any event, the credit will continue to reduce the Companies' income tax expense or property tax expense through 2010.

Q. How do the test year amounts compare to the actual amounts for calendar year 2009 that will be recognized by the Companies in 2010?

A. The test year amounts are less when measured on a revenue requirements basis. KU will recognize $5.555 million (total Company) in reduced property tax expense in 2010 based on its actual 2009 coal purchases, according to its response to KIUC 1-45. I have attached a copy of KU's response to KIUC 1-45 as my Exhibit___(LK-12).

LG&E will recognize $3.535 million in reduced property tax expense in 2010 based on its actual 2009 coal purchases, according to its response to KIUC 1-44. I have attached a copy of LG&E's response to KIUC 1-44 as my Exhibit___(LK-13).

Q. Why do the Companies propose to remove these amounts from their test year revenue requirements?

A. The Companies claim that the credit applies only to coal purchases through 2009 and that the credit is a contingent credit based on coal purchases above a 1999 baseline, according to Mr. Miller's Direct Testimony on pages 2-3.

Q. Are the credits recognized in the test year contingent?

A. No. These amounts were recognized based on actual 2008 coal purchases.

Q. Are the credits that will be recognized in 2010 contingent?

A. No. These amounts will be recognized based on actual 2009 coal purchases, which are known and measurable.

Q. Should the Commission reflect the Kentucky coal tax credit in the Companies' revenue requirement?

A. Yes. The Companies had eligible purchases in 2009 and will record the credits on their accounting books in 2010. The credit will not disappear until 2011. Consequently, the Companies' proposal constitutes a selective post-test year adjustment reaching into 2011, some two years after the end of the test year.

<u>If Coal Tax Credit Is Eliminated, Then Clean Coal Incentive Tax Credit Should Be Included</u>

Q. Is there another tax credit that will replace the coal tax credit in 2010 when TC 2 becomes operational?

A. Yes. KRS 141.428 provides a $2 per ton clean coal incentive tax credit for eligible Kentucky coal purchases, as described by Mr. Miller in his Direct Testimony on page 3. The Companies plan to apply for the credit for the TC2 coal purchases, also according to Mr. Miller, although the Companies have not yet done so.

The tax credit is available for eligible coal purchases used by the taxpayer in a certified clean coal facility, which the statute defines as "an electric generation facility beginning commercial operation on or after January 1, 2005, at a cost greater than one hundred fifty million dollars ($150,000,000) that is located in the Commonwealth of Kentucky and is certified by the Environmental and Public Protection Cabinet as reducing emissions of pollutants released during generation of electricity through the use of clean coal equipment and technologies." KU provided a copy of the statute in response to KIUC 1-46, a copy of which I have attached as my Exhibit___(LK-14.

Q. Have the Companies provided any evidence that they will not qualify for this tax credit?

A. No.

Q. Have the Companies estimated the value of the tax credit under certain assumptions?

A. Yes. KU estimates that it will purchase 804,938 tons of Kentucky coal assuming an 85% capacity factor, according to its response to KIUC 2-11. LG&E estimates that it will purchase 188,813 tons under the same assumptions, according to its response to KIUC 2-8. I have attached a copy of the Companies' responses as my Exhibit__(LK-15) and Exhibit___(LK-16), respectively.

Under these parameters, the KU tax credit will be $1.413 million (804,938 tons times $2 per ton tax credit times 87.792% jurisdictional allocation from Exhibit 1 Schedule 1.38 used for the Kentucky coal tax credit in the test year). Under the same parameters, the LG&E tax credit will be $0.378 million (188,813 tons times $2 per ton tax credit).

If KU applies the tax credit to its state income tax expense, it will reduce its revenue requirement by $2.250 million ($1.413 million reduction in income tax expense divided by 0.6281 gross up factor). If KU applies the tax credit to its property tax expense, it will reduce its revenue requirement by the same amount as the tax credit. Similarly, if LG&E applies the tax credit to its state income tax expense, it will reduce its revenue requirement by $0.605 million ($0.378 million reduction in income tax expense divided by 0.6252 gross-up factor. If LG&E applies the tax credit to its property tax expense, it will reduce its revenue requirement by the same amount as the tax credit. 0.6252.

Q. Do you recommend that the Commission use the clean coal incentive tax credit to quantify the Companies' revenue requirements?

A. No. I recommend that the Commission use the test year coal tax credit and reject the Companies' proposal to eliminate any coal tax credit and to ignore the clean coal incentive tax credit. However, if the Commission does not use the test year coal tax credit, then it should use the clean coal incentive tax credit. The Companies' should not be allowed to retain the benefits of these tax incentives.

<u>Error In Trimble County 2 ACITC Permanent Difference Should Be Corrected</u>

Q. Was there an error in the Companies' filings on Exhibit 1 Schedule 1.45 (adjustment to taxable income for permanent difference on Advance Coal Investment Tax Credit)?

A. Yes. The Companies identified this error in response to Staff 2-47. The KU filing reflected a permanent difference of $1.475 million; however, it should have been $1.031 million. The LG&E filing reflected a permanent difference of $0.346 million; however, it should have been $0.242 million. Consequently, KU's revenue requirement should be reduced by $0.444 million and LG&E's by $0.104 million.

III. RATE OF RETURN ISSUES

<u>Short-Term Debt Is Understated</u>

Q. Please describe the amount of short term debt the Companies included in their capitalization.

A. KU included $17.360 million and LG&E included $0 of short term debt in their adjusted capitalization. These were the amounts outstanding on October 31, 2009, the last day of the test year.

Q. How do the amounts included in their filings compare to the actual amounts of short-term debt used during the test year?

A. They were substantially lower than the actual amounts used during the test year. For KU, the average daily balances by month during the test year ranged from a low of negative $0.478 million (total Company) to a high of $118.573 million (total Company), or an average over the test year of $37.727 million (total Company), according to KU's response to KIUC 1-48. I have attached a copy of

KU's response to KIUC 1-48 as my Exhibit___(LK-17).

For LG&E, the average daily balances by month during the test year ranged from a low of $103.615 million to a high of $330.075 million, or an average over the test year of $162.824 million, according to LG&E's response to KIUC 1-47. I have attached a copy of LG&E's response to KIUC 1-47 as my Exhibit___(LK-18).

Q. How does the amount of short-term debt actually used by the Companies compare to their total capitalization for the test year?

A. For KU, the average balance of short term debt represented slightly more than 1% of its total capitalization. For LG&E, the average balance represented slightly more than 7% of its total capitalization.

Q. What is the significance of the fact that the Companies actually used larger amounts of short term debt during the test year than the amounts reflected in their filings?

A. The significance is that the Companies' actual costs are lower, and in the case of LG&E, substantially lower, than portrayed in their filings and these lower costs are not reflected in their claimed revenue requirements. If the Commission does not reflect an appropriate amount of short-term debt in the capital structure, the Companies will recover from ratepayers an excessive cost of capital grossed-up for income taxes, but actually will finance using substantially lower cost short-term debt. This would allow the Companies to effectively arbitrage their recovery from ratepayers by assuming for ratemaking purposes that they would use a lower amount (KU) or no amount (LG&E) of low cost short-term debt financing, but then actually use additional amounts of short term debt and retain the savings.

The Companies' present cost of short-term debt is 0.20%, according to the monthly updates of its cost of capital provided in these proceedings in response to Staff 1-43. In contrast to this extremely low cost of short-term debt, KU's overall cost of capital is 8.32%, as shown on Exhibit 2 in its filing and grossed-up for income taxes is 11.99%. LG&E's overall cost of capital also is 8.32%, as shown on Exhibit 2 in its filing and grossed-up for income taxes is 12.04%. Thus, the increased cost to ratepayers of the Companies' ratemaking arbitrage is substantial.

Q. Would the use of the average monthly amounts of short term debt during the test year provide a better measure of the short term debt that should be reflected in capitalization than a single day at the end of the test year?

A. Yes. The average monthly amounts of short term debt during the test year reflect the normalized amounts of short term debt based on the Companies' actual usage of this low cost form of financing, unlike the amounts that happen to be outstanding on a single day at the end of the test year. As I noted previously, the amounts of short term debt outstanding vary from month to month and from day to day. In recognition of this fact, other Commissions, such as the Georgia Public Service Commission, have adopted the use of a 13 month average.

In contrast, the amount of short-term debt outstanding on the last day of the test year does not properly capture the use of this low cost form of financing either in the historic test year or going forward. Almost by definition, the balance on the last day of the test year does not reflect a normalized amount of short term debt. At least in concept, a utility could manipulate its short term debt balance so that it was either lower on the last day of the test year or $0 in anticipation of a rate case filing in order to increase its cost of capital and claimed revenue requirement.

Q. Should the Commission temper the use of the actual 13 month average test year short term debt for LG&E?

A. Yes. The use of the actual 13 month average for LG&E is not representative of the Company's policy for maintaining such balances below $100 million. Consequently, the Commission should limit the amount of short term debt of LG&E to the $100 million pursuant to the Companies' policy. The Companies claim in response to KIUC 2-13 (KU) and KIUC 2-10 (LG&E) that they "have a well established operating practice of keeping short-term debt below $100 million (excluding debt incurred to acquire tax-exempt bonds) to preserve liquidity available to response to unanticipated cash needs or adverse long-term debt market conditions." They claim that the balance of short-term debt "will move daily within this range as a result of working capital and capital project funding needs."

Q. Have you quantified the effect of using the average monthly amounts of short term debt during the test year in lieu of the amounts on October 31, 2009

included in the Companies' filings?

A. Yes. The effect is to reduce the KU's revenue requirement by $1.567 million and LG&E's revenue requirement by $9.344 million. I capped the LG&E short-term debt at $100 million. The computations are detailed on my Exhibit___(LK-19) for KU and my Exhibit___(LK-20) for LG&E. In Section I of each exhibit, I reflect the grossed-up cost of capital included in that Company's filing using the Company's cost of capital from Exhibit 2 from each of their filings.

For KU, in Section II, I added $18.061 million (total Company) to the per books short term debt ($37.727 million test year average less $19.666 million on October 31, 2009) and reduced the long-term debt and common equity by an equivalent amount on a prorata basis. For LG&E, in Section II, instead of the $162.824 million actual 13 month test year average, I added $100.000 million (total electric and gas) to the per books short term debt ($100.000 million cap less $0 on October 31, 2009) and reduced the long-term debt and common equity by an equivalent amount on a prorata basis.

I computed the difference in the grossed up rate of return in Section II compared to Section I and then multiplied the difference in the grossed-up rate of return times KU's jurisdictional and LG&E's electric total capitalization, respectively.

<u>Cost of Long-Term Debt Should be Updated</u>

Q. The Commission's historic practice in base rate proceedings is to update the utility's cost of debt prior to the record being closed. Have the Companies updated their cost of debt in response to Staff discovery?

A. Yes. The Companies updated their costs of short term debt and long term debt as of February 28, 2010 in updated responses to PSC 1-43 filed on March 31, 2010. 2008. KU's cost of short term debt declined to 0.20% from 0.22% in its filing and its cost of long-term debt declined to 4.66% from 4.68% in its filing. LG&E's cost of short term debt declined to 0.20% from 0.22% in its filing and its cost of long-term debt declined to 4.58% from 4.61% in its filing. I have attached KU's update as my Exhibit___(LK-21) and LG&E's update as my Exhibit___(LK-22).

Q. Have you quantified the effect of these reductions in the costs of short-term debt and long-term debt on the Companies' revenue requirements?

A. Yes. The effect is to reduce KU's revenue requirement by $0.285 million and LG&E's revenue requirement by $0.256 million. The computations are detailed on my Exhibit___(LK-19) for KU and Exhibit___(LK-20) for LG&E. I made these changes in Section III of these two exhibits and computed the difference in the grossed up rate of return compared to Section II. I then multiplied the difference in the grossed-up rate of return times KU's jurisdictional and LG&E's electric total capitalization, respectively.

<u>Cost of Common Equity Should Be Reduced to Reflect Reasonable Level</u>

Q. Have you quantified the revenue requirement effects of the KIUC return on common equity recommendation addressed by Mr. Richard Baudino?

A. Yes. The effect is to reduce KU's jurisdictional revenue requirement by $46.895 million and LG&E's electric revenue requirement by $26.769 million. The computations are detailed on my Exhibit___(LK-19) for KU and Exhibit___(LK-20) for LG&E. I made the change to the return on common equity in Section IV of these two exhibits and computed the difference in the grossed-up rate of return compared to Section III. I then multiplied the difference in the grossed-up rate of return times KU's jurisdictional and LG&E's electric total capitalization, respectively.

Q. What is the effect on the revenue requirement of each 1.0% return on common equity?

A. For KU, the effect on the revenue requirement of each 1.0% return on common equity is $26.053 million. For LG&E, the effect is $13.942 million.

Q. What is the pretax return on common equity requested by the Companies and that recommended by KIUC?

A. The pretax return on common equity requested by KU is 18.23%. The pretax return on common equity requested by LG&E is 18.31%. The pretax return on common equity recommended by KIUC is 15.44% for KU and 15.38% for LG&E (the difference is due to slight differences in the effect of the Section 199 deduction). The pretax return is the return on common equity that must be recovered from ratepayers in the revenue requirement. It includes federal and state income taxes that must be recovered in the revenue requirement, but that are expensed by the Companies in computing their earned returns. For this purpose, I included only the income tax gross-up to the return on common equity, although the revenue requirement also includes a gross-up for bad debt and the Commission assessment fee.

Investment In EEI Adjustments Should Be Eliminated (KU Only)

Q. In conjunction with your recommendation to include the EEI earnings and investment in the revenue requirement, have you eliminated KU's adjustments to capitalization?

A. Yes. I eliminated the adjustments to reduce capitalization for KU's original investment in EEI, which it allocated across all components. This adjustment increases capitalization by $1.295 million. I also eliminated the adjustment to reduce common equity for the undistributed EEI earnings. This adjustment increases the common equity component of capitalization by $6.208 million. These two adjustments should be made only if the Commission includes the EEI earnings in Operating Income, as I recommended in that section of my testimony.

Q. Have you quantified the effect of eliminating these two KU adjustments on KU's revenue requirement?

A. Yes. The effect is to increase the KU revenue requirement by $0.973 million. The computations are detailed on my Exhibit___(LK-19). In Section V of this exhibit, I eliminated the KU's two EEI adjustments and recomputed the total capitalization and the grossed-up cost of capital. I computed the difference in the grossed-up rate of return in Section V compared to Section IV. I then multiplied the difference in the grossed-up rate of return times KU's jurisdictional capitalization adjusted for these changes.

Q. Does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Lane Kollen

Lane Kollen

Sworn to and subscribed before me on this
20th day of April 2010.

Jessica K. I

Notary Public

JESSICA K. INMAN
MY COMMISSION EXPIRES
NOTARY PUBLIC
JULY 31ST, 2011
CHEROKEE COUNTY, GA

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

IN RE:	APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	) CASE NO. 2009-00548
	APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	) CASE NO. 2009-00549

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA
October 2008

EXHIBIT ____ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than thirty years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present: **J. Kennedy and Associates, Inc.:** Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986: **Energy Management Associates:** Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: **The Toledo Edison Company:** Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

**Expert Testimony Appearances
of
Lane Kollen
As of April 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.

**Expert Testimony Appearances
of
Lane Kollen
As of April 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric	Financial workout plan. Corp.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017- -1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92

**Expert Testimony Appearances
of
Lane Kollen
As of April 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
7/88	M-87017--2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.

Expert Testimony Appearances
of
Lane Kollen
As of April 2010

Date	Case	Jurisdict.	Party	Utility	Subject
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements , detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.

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Date	Case	Jurisdict.	Party	Utility	Subject
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.

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12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission	Gulf States Utilities/Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities/Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95	U-21485 (Supplemental Direct) 12/95 U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co. The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	CT	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities stranded costs, recovery mechanisms.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co. and Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, and American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	21527	TX	Dallas-Ft.Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/00	22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	PUC 22350 SOAH 473-00-1015	TX	The Dallas-Ft. Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp/	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. and Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, Separations methodology

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Date	Case	Jurisdict.	Party	Utility	Subject
07/01	U-21453, U-20925, U-22092 Subdocket B Transmission and Distribution Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	25230	TX	Dallas Ft.-Worth Hospital Council & the Coalition of Independent Colleges & Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 and U-22092		Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless

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Date	Case	Jurisdict.	Party	Utility	Subject
	(Subdocket C)		Staff		conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and The Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.

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of
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As of April 2010**

Date	Case	Jurisdict.	Party	Utility	Subject
11/03	ER03-583-000, ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchase and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459, PUC Docket	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including including valuation issues, ITC, ADIT, excess earnings.

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Date	Case	Jurisdict.	Party	Utility	Subject
05/04	29206 04-169- EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4556 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	Docket No. U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	Docket No. U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case No. 2004-00321 Case No. 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, etal.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and § 199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public. Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas and Electric Co.	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06 05/06	31994 31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change. Retrospective ADFIT, prospective ADFIT.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
3/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPioint Energy Houston Electric	Proposed Regulations affecting flow-through to ratepayers of excess deferred income taxes and investment Tax credits on generation plant that Is sold or deregulated.
4/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated programs costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925 U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co..	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery
04/07	U-29764 Supplemental And Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuctionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue Requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in account 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in account 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.
04/08	2007-00562 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Supplemental Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, incl costs recovered in existing rates, TIER
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, incl projected test year rate base and expenses.
07/08	27163 Panel with Victoria Taylor	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO 08-918-EL-SSO	OH OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-564 2007-565 2008-251 2008-252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09	U-21453,U-20925 U-22092 (Subdocket J)		Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	U-21453, U-20925 U-22092 (Subdocket J) Rebuttal		Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925 U-22092 (Subdocket J) Supplemental Rebuttal		Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	LA	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical v. actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical v. actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal	LA	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical v. actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.

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Date	Case	Jurisdict.	Party	Utility	Subject
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue Requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.

EXHIBIT ____ (LK-2)

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Data Request of Commission Staff
Dated March 1, 2010

Question No. 29

Responding Witness: Robert M. Conroy

Q-29. Refer to Exhibit 1, Reference Schedule 1.07 of the Rives Testimony and page 5 of the Direct Testimony of Robert M. Conroy ("Conroy Testimony").

a. The text on page 6 of the Conroy Testimony states that "KU performed the adjustment in a manner generally consistent with the methodology prescribed by the Commission's Order on rehearing in Case No. 98-474, " . . . however, total off-system sales revenues, inclusive of Intercompany sales, are used in the calculation." Identify and describe all aspects of the proposed adjustment that cause it to be "generally consistent" rather than "entirely consistent" with the methodology previously prescribed by the Commission.

b. Reference Schedule 1.07 uses an average environmental surcharge factor of 9.52 percent to calculate the off-system sales environmental cost. Explain whether this is a "simple average" of the surcharge factors in column 2 of the schedule or a "weighted average" derived by multiplying the monthly amounts in column 1 by the factors in column 2, summing the results, and dividing that sum by the test year total in column 1.

c. If the calculation of the adjustment is based on the "simple average" of the monthly surcharge factors in column 2 of the schedule, explain why this was done and provide a revised version of the calculation using the weighted average approach described above.

A-29. a. Reference Schedule 1.07 calculates the adjustment to off-system sales revenues to recognize environmental costs associated with those sales. The adjustment is calculated using total off-system sales revenues, in contrast with the methodology adopted by the Commission in Case No. 98-474, where intercompany revenues were excluded from off-system sales revenues.

In Case No. 2003-00434, KU revised its Rives Exhibit 1, Reference Schedule 1.05 to appropriately include intercompany revenues in the determination of the adjustment to off-system sales revenues. This revised adjustment was explained in KU's supplemental response to Question No. 54 of the Initial Data Request of the Kentucky

Industrial Utilities Customers and on pages 37 and 38 of Mr. Seelye's rebuttal testimony.

In its June 30, 2004 Order in that case, the Commission found the revised adjustment to be reasonable and accepted it, as stated in general terms on pages 24 and 25, and specifically on page 2 of Appendix F. Therefore, KU's adjustment on Schedule .1.07 is "generally consistent" with the Commission's Order in Case 98-474 and "entirely consistent" with the Commission's Order in Case No. 2003-00434. When preparing this same adjustment in KU's prior rate case, Case No. 2008-00251, the Companies inadvertently utilized the methodology presented in the original filing in Case No. 2003-00434 instead of the revised version from Mr. Seelye's rebuttal testimony. Because Case No. 2008-00251 was ultimately settled, the issue was not addressed in that case.

Please see the attached copies of the relevant portions of the documents referenced in this response.

b. The average environmental surcharge factor of 9.52 percent on Reference Schedule 1.07 is a simple average of the surcharge factors in column 2.

c. The simple average is consistent with the method adopted by the Commission in Case No. 98-474, and has been used consistently by KU in all base rate proceedings since that time. See the attachment to part c of this response for the requested calculation.

KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00434

Supplemental Response to First Data Request of the KIUC Dated February 3, 2004
Filed – February 27, 2004

Question No. 54

Responding Witness: Michael S. Beer / *W. Steven Seelye*

Q-69. Refer to Rives Exhibit 1 Schedule 1.05. Please indicate whether the off-system sales revenues used in the actual computation of the Companies' ECR tariff rates also exclude intercompany off-system sales revenues and are consistent with the Companies' computations in column 3 of this schedule. If the Companies' off-system sales revenues used in the actual ECR tariff rates do not exclude intercompany sales revenues, then please explain why the Companies excluded these revenues on this schedule.

A-69. The computation of the Company's ECR monthly billing factors uses total Company revenues to determine the retail jurisdictional percent of ECR recovery. Consistent with the Commission's Order in Case No. 2000-106, total Company revenues include all off-system sales revenues other than brokered sales.

The determination of the adjustment of off-system sales revenue for environmental surcharge costs is consistent with the Commission Order in Case No. 98-474.

The purpose of the adjustment shown in Rives Exhibit 1, Schedule 1.05, is to adjust off-system sales margins, which are credited against revenue requirements in the rate case, for the environmental costs allocated to off-system sales in the monthly ECR calculations. Because ECR costs, including those allocated to off-system sales, are removed from the determination of revenue requirements, the margins associated with the Company's off-system sales are overstated by the amount of the environmental costs allocated to off-system sales.

As explained in the original response, the Company was following prior practice in making this adjustment. However, the Company agrees that Off-System Sales Inter-company Revenue should not have been excluded from Off-System Sales Revenue in Rives Exhibit 1, Schedule 1.05, because excluding those revenues does not allow the full amount of environmental costs assigned to off-system sales to be reflected in the adjustment. Attached is a revised schedule showing a calculation of the pro-forma adjustment without removing Inter-company Revenue.

level would be removed from the debt component of capitalization, and the difference between test-year expenses and the rolled-in expenses would be removed from expenses during the test year. Test year revenues would be adjusted to remove ECR revenues net of the rolled-in amounts. If we understand the data requests correctly, this approach would correspond to the methodology suggested in Question 34 to KU and Question 38 to LG&E of the Commisison Staff's second data request dated February 3, 2004, in this proceeding.

Q. Do you have any fundamental problems with either of these alternatives?

A. No. Either of these alternatives would allow the Companies the opportunity to recover their original plan costs, including a fair, just and reasonable return on their investments. Our preference, however, is to terminate the ECR surcharge for the original compliance plans.

(g) Off-System Sales in the ECR and Adjustment for Mismatch in Fuel Cost Recovery

Q. Are the intervenor witnesses being evenhanded about two errors that were made in the off-system sales revenue adjustment for the ECR calculation and in the adjustment for the mismatch in fuel cost recovery for the year ending September 20, 2003?

A. No. In preparing responses to data requests submitted by the Commission Staff, the KIUC and the AG, it came to our attention that there were errors in the off-system sales revenue adjustment for the ECR calculation, Reference Schedule 1.05 of Rives Exhibit 1 and in the adjustment concerning the mismatch in fuel cost recovery for the test year, Reference Schedule 1.01 of Rives Exhibit 1. Even though the errors were fully explained in responses to data requests[1], witnesses for the KIUC and AG ignored these errors in presenting their recommended revenue requirements, apparently because correcting the errors would increase the Companies' revenue requirements.

Q. Please explain the adjustment and the nature of the error relating to the adjustment in the off-system sales revenue for the ECR.

A. In the Companies' environmental surcharge calculations, a portion of the environmental costs incurred is allocated to off-system sales. The Commission determined in approving the Companies' ECRs that it is appropriate to allocate a portion of environmental costs to off-system sales by observing that environmental costs are incurred to make off-system sales just as they are to make retail sales. The purpose of the pro-forma off-system sales revenue adjustment for the ECR calculation (Reference Schedule 1.05) is to adjust off-system sales margins, which are credited against revenue requirements in the rate case, for the environmental costs allocated to off-system sales in the monthly environmental surcharge calculations. This adjustment was approved in Case Nos. 98-426 and 98-474 and recognized in all subsequent ESM filings.

In the original calculation of this adjustment, inter-company revenue was subtracted from total off-system sales revenue to determine the environmental costs for off-system sales that should be subtracted from revenues from off-system sales in this proceeding. When preparing a response to a KIUC data request, we realized that intercompany revenues ***<u>should not have been</u>*** subtracted from off-system sales revenue. Environmental costs are allocated to intercompany revenue in the monthly environmental surcharge calculations. However, there is no mechanism in place for recovering these

[1] The error was explained in the supplemental responses to question 54 to LG&E and question 69 to KU of the first data request of the KIUC dated February 3, 2004, and filed February 27, 2004. The error was also brought to light in LG&E's response to question 53 of the supplemental data request of the Attorney General dated March 1, 2004.

costs from ratepayers. Although KU pays LG&E (and vice versa) for the cost of the intercompany sales, KU does not pay LG&E for the portion of environmental costs allocated to intercompany sales in the environmental surcharge calculations. These costs are not recovered through either LG&E or KU's ECR mechanism, nor are they recovered through either utility's FAC. Intercompany revenues represent charges paid by one utility for transfers of electric energy to the other. Therefore, unless these environmental costs are subtracted from intercompany revenues in this proceeding, the Companies will be denied the opportunity from ever recovering these legitimately incurred costs. It is thus reasonable that LG&E and KU be allowed to revise Reference Schedule 1.05 of Rives Exhibit 1 to correct for this oversight.

Q. Have you prepared a revised Reference Schedule 1.05?

A. Yes. Revised Reference Schedule 1.05 for LG&E and KU are included as pages 1 and 2 of Seelye Rebuttal Exhibit 2.

Q. Please explain KU's adjustment and nature of the error relating to the mismatch in fuel cost recovery for the test period.

A. As I discussed in my direct testimony, via this adjustment, the mismatch between fuels costs and fuel cost recovery through KU's FAC will be eliminated consistent with Commission practice. An error was detected, however, in PSC 2-15(a), when the Commission Staff noted that the expense amount shown in the proposed adjustment was taken from KU's Form A filing for November, 2003 made on December 16, 2003. In fact, the expense amount included on that Form A for September 2003 was incorrectly listed as $4,269,288, when it previous decisions by the Commission when items are removed from the calculation of rate base. Therefore, the Commission has reduced KU's Kentucky jurisdictional capitalization, on a pro rata basis, by $7,408,501.

Based on the findings herein, the Commission has determined that KU's test-year-end Kentucky jurisdictional capitalization should be $1,297,055,596. The calculation of the jurisdictional capitalization is shown in Appendix E.

REVENUES AND EXPENSES

For the test year, KU reported actual net operating income from Kentucky jurisdictional operations of $86,167,531.[2] KU proposed a series of adjustments to revenues and expenses to reflect more current and anticipated operating conditions, resulting in an adjusted net operating income from Kentucky jurisdictional operations of $60,956,866.[3] The AG also proposed numerous revenue and expense adjustments, resulting in net operating income from Kentucky jurisdictional operations of $84,669,000.[4] The Commission finds that 21 of the adjustments, proposed in KU's application and accepted by the AG, are reasonable and will be accepted. During the proceeding, KU identified and corrected errors in several other adjustments originally proposed in its application. The Commission finds that three of these other adjustments, as corrected by KU and accepted by the AG, are reasonable and they will also be accepted. All of these 24 adjustments are set forth in detail in Appendix F, which is attached hereto.

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[2] Rives Direct Testimony, Rives Exhibit 1, page 1 of 3, line 1.

[3] Id., page 3 of 3, line 42.

[4] Majoros Accounting Direct Testimony, Exhibit MJM-2.

APPENDIX F

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00434 DATED

Schedule of Adjustments

The following adjustments were proposed by KU in its application, accepted by the AG, and have been found reasonable and accepted by the Commission. The "+" indicates an increase while "-" indicates a decrease.

	Description	Reference Rives Exhibit 1	Change to Revenues	Change to Expenses
1.	Adjustment to eliminate unbilled revenues.	Sch. 1.00	+$675,000	0
2.	Adjust base rates and Fuel Adjustment Clause ("FAC") to reflect a full year of FAC roll-in.	Sch. 1.02	+$1,417,623	0
3.	Adjustment to eliminate environmental surcharge revenues and expenses.	Sch. 1.03	-$25,039,979	-$248,468
4.	Adjust base rate revenues to reflect a full year of the environmental surcharge roll-in.	Sch. 1.04	+$17,986,813	0
5.	Eliminate electric brokered sales revenues and expenses.	Sch. 1.06	-$5,571,256	-$7,725,329
6.	Eliminate electric ESM revenues collected.	Sch. 1.07	-$4,604,742	0
7.	Eliminate ESM, environmental surcharge, and FAC in Rate Refund Account 449.	Sch. 1.08	+$1,630,147	0
8.	Eliminate demand-side management revenues and expenses.	Sch. 1.09	-$2,942,935	-$2,946,471
9.	Eliminate advertising expenses pursuant to 807 KAR 5:016.	Sch. 1.15	0	-$45,386
10.	Adjustment to remove One-Utility costs.	Sch. 1.18	0	-$1,550,907
11.	Adjustment for VDT net savings to shareholders.	Sch. 1.20	0	+$2,895,000

APPENDIX F (continued)

Description	Reference Rives Exhibit 1	Change to Revenues	Change to Expenses
12. Adjust VDT-related revenues and expenses to settlement agreement.	Sch. 1.21	+$85,337	-$466,280
13. Adjustment for merger savings.	Sch. 1.22	-$2,564,269	+$18,968,825
14. Adjustment to eliminate LG&E/KU merger amortization expense.	Sch. 1.23	0	-$2,726,510
15. Adjustment for MISO Schedule 10 credits.	Sch. 1.24	0	+$843,344
16. Adjust for cumulative effect of accounting change. [AG withdrew objection to adjustment; AG Post-Hearing Brief at 17]	Sch. 1.25	0	+$8,434,618
17. Adjustment to remove E. W. Brown legal expenses.	Sch. 1.27	0	-$3,126,995
18. Adjust for customer rate switching.	Sch. 1.28	-$1,898,980	0
19. Adjustment for sales tax refunds.	Sch. 1.29	0	+$120,391
20. Adjustment for 1992 management audit fees.	Sch. 1.32	0	+$163,982
21. Adjust for prior income tax true-ups and adjustments.	Sch. 1.36	0	+$681,889

APPENDIX F (continued)

The following adjustments were proposed in the application and later revised by KU, accepted by the AG, and have been found reasonable and accepted by the Commission. The "+" indicates an increase while "-" indicates a decrease.

	Description	Revision Reference	Change to Revenues	Change to Expenses
1.	Adjust mismatch in fuel cost recovery. [Rives Ex. 1, Sch. 1.01]	Seelye Rebuttal Ex. 2	-$35,887,728	-$28,474,767
2.	Adjust off-system sales revenues for the environmental surcharge calculations. [Rives Ex. 1, Sch. 1.05]	Seelye Rebuttal Ex. 2	-$2,266,829	0
3.	Adjustment to reflect amortization of ESM audit expenses. [Rives Ex. 1, Sch. 1.17]	Scott Rebuttal Ex. 5	0	+$63,933

Exhibit 1
Reference Schedule 1.07
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

Off-System Sales Revenue Adjustment for the ECR Calculation
For the Twelve Months Ended October 31, 2009

	(1)	(2)	(3)	(4)
	KU Off-System Sales Revenue	Monthly Environmental Surcharge Factor (1)	Weighted Avg Environmental Surcharge Factor	Off-System Sales Environmental Cost (Col. 1 * 3)
Nov-08	$ 16,763,550	7.38%	7.88%	$ 1,321,802
Dec-08	10,407,202	6.50%	7.88%	820,605
Jan-09	4,800,653	6.54%	7.88%	378,530
Feb-09	2,308,018	6.52%	7.88%	181,987
Mar-09	2,365,975	9.27%	7.88%	186,557
Apr-09	1,258,387	9.89%	7.88%	99,223
May-09	3,233,654	11.69%	7.88%	254,973
Jun-09	706,503	9.68%	7.88%	55,708
Jul-09	286,233	11.58%	7.88%	22,569
Aug-09	336,928	11.94%	7.88%	26,567
Sep-09	335,449	11.20%	7.88%	26,450
Oct-09	2,310,656	12.03%	7.88%	182,195
Total	$ 45,113,208			$ 3,557,166
Weighted Avg		7.88%		
Kentucky Jurisdiction (Ref. Sch. Allocators)				86.685%
Total				$ 3,083,529
Adjustment				$ (3,083,529)

(1) ES Form 1.00

EXHIBIT ____ (LK-3)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2009-00549

**Response to Second Data Request of Commission Staff
Dated March 1, 2010**

Question No. 33

Responding Witness: Robert M. Conroy

Q-33. Refer to Exhibit 1, Reference Schedule 1.07, of the Rives Testimony and pages 5 – 6 of the Testimony of Robert M. Conroy ("Conroy Testimony").

a. The text on page 6 of the Conroy Testimony states that "LG&E performed the adjustment in a manner generally consistent with the methodology prescribed by the Commission's Order on rehearing in Case No. 98-426, . . . however, total off-system sales revenues, inclusive of Intercompany sales, are used in the calculation." Identify and describe all aspects of the proposed adjustment that cause it to be "generally consistent" rather than "entirely consistent" with the methodology previously prescribed by the Commission.

b. Reference Schedule 1.07 uses an average environmental surcharge factor of 1.20 percent to calculate the off-system sales environmental cost. Explain whether this is a "simple average" of the surcharge factors in column 2 of the schedule or a "weighted average" derived by multiplying the monthly amounts in column 1 by the factors in column 2, summing the results, and dividing that sum by the test year total in column 1.

c. If the calculation of the adjustment is based on the "simple average" of the monthly surcharge factors in column 2 of the schedule, explain why this was done and provide a revised version of the calculation using the weighted average approach described above.

A-33. a. Reference Schedule 1.07 calculates the adjustment to off-system sales revenues to recognize environmental costs associated with those sales. The adjustment is calculated using total off-system sales revenues, in contrast with the methodology adopted by the Commission in Case No. 98-426, where intercompany revenues were excluded from off-system sales revenues.

In Case No. 2003-00433, LG&E revised its Rives Exhibit 1, Reference Schedule 1.05 to appropriately include intercompany revenues in the determination of the adjustment to off-system sales revenues. This revised adjustment was explained in LG&E's supplemental response to Question No. 69 of the Initial Data Request of the Kentucky Industrial Utilities Customers, in response to Question No. 53 of the

Supplemental Data Request of the Attorney General, and on pages 37 and 38 of Mr. Seelye's rebuttal testimony.

In its June 30, 2004 Order in that case, the Commission found the revised adjustment to be reasonable and accepted it, as stated in general terms on pages 24 and 25, and specifically on page 2 of Appendix F. Therefore, LG&E's adjustment on Schedule 1.07 is "generally consistent" with the Commission's Order in Case 98-426 and "entirely consistent" with the Commission's Order in Case No. 2003-00433. When preparing this same adjustment in LG&E's prior rate case, Case No. 2008-00252, the Companies inadvertently utilized the methodology presented in the original filing of in Case No. 2003-00433 instead of the revised version from Mr. Seelye's rebuttal testimony. Because Case No. 2008-00252 was ultimately settled, the issue was not addressed in that case.

Please see the attached copies of the relevant portions of the documents referenced in this response.

b. The average environmental surcharge factor of 1.20 percent on Reference Schedule 1.07 is a simple average of the surcharge factors in column 2.

c. The simple average is consistent with the method adopted by the Commission in Case No. 98-426, and has been used consistently by LG&E in all base rate proceedings since that time. See the attachment to part c of this response for the requested calculation.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2003-00433

Supplemental Response to First Data Request of the KIUC Dated February 3, 2004
Filed – February 27, 2004

Question No. 69

Responding Witness: Michael S. Beer / *W. Steven Seelye*

Q-69. Refer to Rives Exhibit 1 Schedule 1.05. Please indicate whether the off-system sales revenues used in the actual computation of the Companies' ECR tariff rates also exclude intercompany off-system sales revenues and are consistent with the Companies' computations in column 3 of this schedule. If the Companies' off-system sales revenues used in the actual ECR tariff rates do not exclude intercompany sales revenues, then please explain why the Companies excluded these revenues on this schedule.

A-69. The computation of the Company's ECR monthly billing factors uses total Company revenues to determine the retail jurisdictional percent of ECR recovery. Consistent with the Commission's Order in Case No. 2000-105, total Company revenues include all off-system sales revenues other than brokered sales.

The determination of the adjustment of off-system sales revenue for environmental surcharge costs is consistent with the Commission Order in Case No. 98-426.

The purpose of the adjustment shown in Rives Exhibit 1, Schedule 1.05, is to adjust off-system sales margins, which are credited against revenue requirements in the rate case, for the environmental costs allocated to off-system sales in the monthly ECR calculations. Because ECR costs, including those allocated to off-system sales, are removed from the determination of revenue requirements, the margins associated with the Company's off-system sales are overstated by the amount of the environmental costs allocated to off-system sales.

As explained in the original response, the Company was following prior practice in making this adjustment. However, the Company agrees that Off-System Sales Inter-company Revenue should not have been excluded from Off-System Sales Revenue in Rives Exhibit 1, Schedule 1.05, because excluding those revenues does not allow the full amount of environmental costs assigned to off-system sales to be reflected in the adjustment. Attached is a revised schedule showing a calculation of the pro-forma adjustment without removing Inter-company Revenue.

level would be removed from the debt component of capitalization, and the difference between test-year expenses and the rolled-in expenses would be removed from expenses during the test year. Test year revenues would be adjusted to remove ECR revenues net of the rolled-in amounts. If we understand the data requests correctly, this approach would correspond to the methodology suggested in Question 34 to KU and Question 38 to LG&E of the Commisison Staff's second data request dated February 3, 2004, in this proceeding.

Q. Do you have any fundamental problems with either of these alternatives?

A. No. Either of these alternatives would allow the Companies the opportunity to recover their original plan costs, including a fair, just and reasonable return on their investments. Our preference, however, is to terminate the ECR surcharge for the original compliance plans.

(g) Off-System Sales in the ECR and Adjustment for Mismatch in Fuel Cost Recovery

Q. Are the intervenor witnesses being evenhanded about two errors that were made in the off-system sales revenue adjustment for the ECR calculation and in the adjustment for the mismatch in fuel cost recovery for the year ending September 20, 2003?

A. No. In preparing responses to data requests submitted by the Commission Staff, the KIUC and the AG, it came to our attention that there were errors in the off-system sales revenue adjustment for the ECR calculation, Reference Schedule 1.05 of Rives Exhibit 1 and in the adjustment concerning the mismatch in fuel cost recovery for the test year, Reference Schedule 1.01 of Rives Exhibit 1. Even though the errors were fully explained in responses to data requests[1], witnesses for the KIUC and AG ignored these errors in presenting their recommended revenue requirements, apparently because correcting the errors would increase the Companies' revenue requirements.

Q. **Please explain the adjustment and the nature of the error relating to the adjustment in the off-system sales revenue for the ECR.**

A. In the Companies' environmental surcharge calculations, a portion of the environmental costs incurred is allocated to off-system sales. The Commission determined in approving the Companies' ECRs that it is appropriate to allocate a portion of environmental costs to off-system sales by observing that environmental costs are incurred to make off-system sales just as they are to make retail sales. The purpose of the pro-forma off-system sales revenue adjustment for the ECR calculation (Reference Schedule 1.05) is to adjust off-system sales margins, which are credited against revenue requirements in the rate case, for the environmental costs allocated to off-system sales in the monthly environmental surcharge calculations. This adjustment was approved in Case Nos. 98-426 and 98-474 and recognized in all subsequent ESM filings.

In the original calculation of this adjustment, inter-company revenue was subtracted from total off-system sales revenue to determine the environmental costs for off-system sales that should be subtracted from revenues from off-system sales in this proceeding. When preparing a response to a KIUC data request, we realized that intercompany revenues ***should not have been*** subtracted from off-system sales revenue. Environmental costs are allocated to intercompany revenue in the monthly environmental surcharge calculations. However, there is no mechanism in place for recovering these

[1] The error was explained in the supplemental responses to question 54 to LG&E and question 69 to KU of the first data request of the KIUC dated February 3, 2004, and filed February 27, 2004. The error was also brought to light in LG&E's response to question 53 of the supplemental data request of the Attorney General dated March 1, 2004.

costs from ratepayers. Although KU pays LG&E (and vice versa) for the cost of the intercompany sales, KU does not pay LG&E for the portion of environmental costs allocated to intercompany sales in the environmental surcharge calculations. These costs are not recovered through either LG&E or KU's ECR mechanism, nor are they recovered through either utility's FAC. Intercompany revenues represent charges paid by one utility for transfers of electric energy to the other. Therefore, unless these environmental costs are subtracted from intercompany revenues in this proceeding, the Companies will be denied the opportunity from ever recovering these legitimately incurred costs. It is thus reasonable that LG&E and KU be allowed to revise Reference Schedule 1.05 of Rives Exhibit 1 to correct for this oversight.

Q. **Have you prepared a revised Reference Schedule 1.05?**

A. Yes. Revised Reference Schedule 1.05 for LG&E and KU are included as pages 1 and 2 of Seelye Rebuttal Exhibit 2.

Q. **Please explain KU's adjustment and nature of the error relating to the mismatch in fuel cost recovery for the test period.**

A. As I discussed in my direct testimony, via this adjustment, the mismatch between fuels costs and fuel cost recovery through KU's FAC will be eliminated consistent with Commission practice. An error was detected, however, in PSC 2-15(a), when the Commission Staff noted that the expense amount shown in the proposed adjustment was taken from KU's Form A filing for November, 2003 made on December 16, 2003. In fact, the expense amount included on that Form A for September 2003 was incorrectly listed as $4,269,288, when it adjustment for the ARO asset. In order to be consistent with LG&E's efforts to remove the impact of the adoption of SFAS No. 143, it is necessary to exclude the ARO assets from LG&E's electric capitalization. Such an adjustment is also consistent with previous decisions by the Commission when items are removed from the calculation of rate base. Therefore, the Commission has reduced LG&E's electric capitalization, on a pro rata basis, by $4,585,010.

Based on the findings herein, the Commission has determined that LG&E's test-year-end electric capitalization should be $1,484,965,466. The calculation of the electric capitalization is shown in Appendix E.

REVENUES AND EXPENSES

For the test year, LG&E reported actual net operating income from electric operations of $108,683,393.[2] LG&E proposed a series of adjustments to revenues and expenses to reflect more current and anticipated operating conditions, resulting in an adjusted net operating income from electric operations of $68,010,218.[3] The AG also proposed numerous revenue and expense adjustments, resulting in adjusted net operating income from electric operations of $87,108,000.[4] The Commission finds that 20 of the adjustments, proposed in LG&E's application and accepted by the AG, are reasonable and will be accepted. During the proceeding, LG&E identified and corrected errors in several other adjustments originally proposed in its application. The Commission finds that three of these other adjustments, as corrected by LG&E and

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[2] Rives Direct Testimony, Rives Exhibit 1, page 1 of 3, line 1.

[3] Id., page 3 of 3, line 44.

[4] Henkes Electric Direct Testimony, Schedule RJH-4.

accepted by the AG, are reasonable and they will also be accepted. All of these 23 adjustments are set forth in detail in Appendix F, which is attached hereto.

The Commission makes the following modifications to the remaining proposed adjustments:

Unbilled Revenues

LG&E proposed an adjustment to eliminate the effect of unbilled electric revenues for rate-making purposes. The rationale for such an adjustment is to develop a better match of test-year revenues and expenses, using as-billed revenues for rate-making purposes rather than the revenues recorded on an accrual basis for accounting purposes. LG&E made its adjustment by shifting unbilled revenues for the month immediately preceding the test year into the test year (when they were actually billed) and shifting unbilled revenues for the last month of the test year to the first month after the test year. This has the effect of netting the amount of unbilled revenues at test-year-end and at the beginning of the test year. LG&E's adjustment reduced electric revenues by $1,867,000.

The AG did not oppose LG&E's unbilled revenues adjustment, but he did propose a corresponding electric expense adjustment to reflect the expense side of an adjustment that reduces test-year sales volumes by 4,095,000 Kwh. The AG calculated an expense reduction of $1,042,000 based on the 55.79 percent operating ratio used by LG&E to calculate its customer growth adjustment.

LG&E objected to the AG's expense adjustment. Since the revenues eliminated by LG&E's adjustment included the recovery of environmental surcharge, fuel clause and demand-side management costs that are removed from test-year operating results

APPENDIX F

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00433 DATED

Schedule of Adjustments

The following adjustments were proposed by LG&E in its application, accepted by the AG, and have been found reasonable and accepted by the Commission. The "+" indicates an increase while "-" indicates a decrease.

	Description	Reference Rives Exhibit 1	Change to Revenues	Change to Expenses
1.	Adjust mismatch in fuel recovery.	Sch. 1.01	-$4,406,145	-$2,005,300
2.	Adjust base rates and Fuel Adjustment Clause ("FAC") reflect a full year of FAC roll-in.	Sch. 1.02	+$547,244	0
3.	Adjustment to eliminate environmental surcharge revenues and expenses.	Sch. 1.03	-$11,228,429	-$1,766,344
4.	Eliminate electric brokered sales revenues and expenses.	Sch. 1.06	-$5,389,000	-$7,811,321
5.	Eliminate electric ESM revenues collected.	Sch. 1.07	-$6,974,780	0
6.	Eliminate ESM, environmental surcharge, and FAC in Rate Refund Account 449.	Sch. 1.08	-$7,150,231	0
7.	Eliminate demand-side management revenues and expenses.	Sch. 1.09	-$3,277,501	-$3,280,013
8.	Eliminate advertising expenses pursuant to 807 KAR 5:016.	Sch. 1.15	0	-$62,499
9.	Adjustment to remove One-Utility costs.	Sch. 1.18	0	-$1,061,924
10.	Adjustment for VDT net savings to shareholders.	Sch. 1.20	0	+$5,640,000
11.	Adjust VDT-related revenues and expenses to settlement agreement.	Sch. 1.21	+$44,485	-$224,718
12.	Adjustment for merger savings.	Sch. 1.22	-$2,758,795	+$19,427,401

APPENDIX F (continued)

	Description	Reference Rives Exhibit 1	Change to Revenues	Change to Expenses
13.	Adjustment to eliminate LG&E/KU merger amortization expense.	Sch. 1.23	0	-$2,722,005
14.	Adjustment for MISO Schedule 10 credits.	Sch. 1.24	0	+$709,577
15.	Adjust for cumulative effect of accounting change. [AG withdrew objection to adjustment; AG Post-Hearing Brief at 12]	Sch. 1.25	0	+$5,280,909
16.	Adjustment to remove E. W. Brown legal expenses.	Sch. 1.27	0	-$2,157,640
17.	Adjust for customer rate switching and customer plant closing.	Sch. 1.28	+$6,445	0
18.	Adjustment for corporate office lease expense.	Sch. 1.29	0	+$1,798,420
19.	Adjust for Cane Run repair refund.	Sch. 1.30	0	+$3,588,000
20.	Adjust for prior income tax true-ups and adjustments.	Sch. 1.38	0	-$58,593

The following adjustments were proposed in the application and later revised by LG&E, accepted by the AG, and have been found reasonable and accepted by the Commission. The "+" indicates an increase while "-" indicates a decrease.

	Description	Revision Reference	Change to Revenues	Change to Expenses
1.	Adjust base rate revenues to reflect a full year of the environmental surcharge roll-in. [Rives Ex. 1, Sch. 1.04]	PSC 3-35	+$717,788	0
2.	Adjust off-system sales revenues for the environmental surcharge calculations. [Rives Ex. 1, Sch. 1.05]	Seelye Rebuttal Ex. 2	-$2,925,817	0
3.	Adjustment to reflect amortization of ESM audit expenses. [Rives Ex. 1, Sch. 1.17]	Scott Rebuttal Ex. 5	0	+$63,933

EXHIBIT ___(LK-4)

Kentucky Utilities Company and Louisville Gas and Electric Company
KIUC's Recommendation to Normalize Off-System Sales Margins
($)

	Intersystem Off-System Sales Revenues Monthly ECR Filings	Off-System Sales Cost of Fuel Monthly Fuel Filings	Off-System Sales Margins
Kentucky Utilities Company			
Twelve Months Ended 12-31-2005	128,185,637	95,156,288	33,029,349
Twelve Months Ended 12-31-2006	85,421,897	65,809,314	19,612,583
Twelve Months Ended 12-31-2007	50,719,786	40,752,971	9,966,815
Twelve Months Ended 12-31-2008	96,723,316	83,791,493	12,931,823
Twelve Months Ended 10-31-2009	45,113,208	40,629,402	4,483,806
Average Off-System Sales Margins			16,004,875
Off-System Sales Margins in Test Year (Total Co)			4,483,806
Normalization Increase to OSS Margins (Total Co)			11,521,069
Kentucky Jurisdictional % (from Sched 1.07)			86.685%
Normalization Increase to OSS Margins (Jurisd)			9,987,039
Louisville Gas and Electric Company			
Twelve Months Ended 12-31-2005	259,612,909	191,833,293	67,779,616
Twelve Months Ended 12-31-2006	207,530,954	167,326,722	40,204,232
Twelve Months Ended 12-31-2007	163,023,282	134,076,606	28,946,676
Twelve Months Ended 12-31-2008	238,629,677	189,093,281	49,536,396
Twelve Months Ended 10-31-2009	169,469,043	151,248,885	18,220,158
Average Off-System Sales Margins			40,937,416
Off-System Sales Margins in Test Year			18,220,158
Normalization Increase to OSS Margins			22,717,258

Kentucky Utilities Company and Louisville Gas and Electric Company
KIUC's Recommendation to Normalize Off-System Sales Margins
($)

	Intersystem Off-System Sales Revenues Monthly ECR Filings	Off-System Sales Cost of Fuel Monthly Fuel Filings	Off-System Sales Margins
Kentucky Utilities Company			
2005			
January	15,389,623	10,586,964	4,802,659
February	12,700,238	9,378,404	3,321,834
March	12,650,080	8,415,396	4,234,684
April	5,157,811	4,137,936	1,019,875
May	8,553,721	6,766,830	1,786,891
June	7,692,007	6,777,300	914,707
July	7,192,285	5,156,333	2,035,952
August	10,018,698	7,024,829	2,993,869
September	13,442,608	9,969,919	3,472,689
October	6,195,963	4,943,233	1,252,730
November	14,242,723	10,621,055	3,621,668
December	14,949,880	11,378,089	3,571,791
Sub-Total	128,185,637	95,156,288	33,029,349
Kentucky Utilities Company			
2006			
January	11,576,748	7,667,716	3,909,032
February	4,880,104	3,509,680	1,370,424
March	3,202,071	2,344,352	857,719
April	3,628,121	2,729,762	898,359
May	8,285,712	6,326,621	1,959,091
June	6,248,973	5,060,239	1,188,734
July	7,822,030	6,570,913	1,251,117
August	4,873,202	4,119,201	754,001
September	6,455,978	4,771,100	1,684,878
October	7,056,404	5,711,352	1,345,052
November	15,247,894	11,944,517	3,303,377
December	6,144,659	5,053,861	1,090,798
Sub-Total	85,421,897	65,809,314	19,612,583

Kentucky Utilities Company and Louisville Gas and Electric Company
KIUC's Recommendation to Normalize Off-System Sales Margins
($)

	Intersystem Off-System Sales Revenues Monthly ECR Filings	Off-System Sales Cost of Fuel Monthly Fuel Filings	Off-System Sales Margins
Kentucky Utilities Company			
2007			
January	9,078,262	7,560,643	1,517,619
February	5,720,530	4,646,975	1,073,555
March	4,054,038	3,293,956	760,082
April	1,872,583	1,565,826	306,757
May	2,893,472	2,176,498	716,974
June	3,421,235	2,562,710	858,525
July	3,762,428	2,976,137	786,291
August	1,832,015	1,505,790	326,225
September	2,907,154	2,331,010	576,144
October	5,250,561	4,144,722	1,105,839
November	3,827,418	3,157,795	669,623
December	6,100,091	4,830,909	1,269,182
Sub-Total	50,719,786	40,752,971	9,966,815
Kentucky Utilities Company			
2008			
January	6,669,148	5,469,193	1,199,955
February	2,841,789	2,387,794	453,995
March	7,301,946	6,232,583	1,069,363
April	5,316,024	4,381,929	934,095
May	6,993,353	5,810,317	1,183,036
June	5,263,389	4,458,477	804,912
July	6,287,326	4,781,347	1,505,979
August	5,517,680	4,513,691	1,003,989
September	8,771,355	7,404,474	1,366,881
October	14,590,554	13,404,448	1,186,106
November	16,763,550	15,163,801	1,599,749
December	10,407,202	9,783,439	623,763
Sub-Total	96,723,316	83,791,493	12,931,823

Kentucky Utilities Company and Louisville Gas and Electric Company
KIUC's Recommendation to Normalize Off-System Sales Margins
($)

	Intersystem Off-System Sales Revenues Monthly ECR Filings	Off-System Sales Cost of Fuel Monthly Fuel Filings	Off-System Sales Margins
Kentucky Utilities Company			
2009			
January	4,800,652	3,869,140	931,512
February	2,308,018	2,003,372	304,646
March	2,365,975	2,090,436	275,539
April	1,258,387	1,154,796	103,591
May	3,233,653	2,914,707	318,946
June	706,503	628,088	78,415
July	286,234	252,704	33,530
August	336,928	304,402	32,526
September	335,449	314,155	21,294
October	2,310,656	2,150,362	160,294
Louisville Gas and Electric Company			
2005			
January	28,271,309	19,002,601	9,268,708
February	27,110,770	18,475,411	8,635,359
March	25,259,670	15,694,979	9,564,691
April	14,425,519	10,969,516	3,456,003
May	19,501,205	16,836,681	2,664,524
June	16,273,168	16,359,134	(85,966)
July	6,380,374	5,025,972	1,354,402
August	13,312,090	9,701,467	3,610,623
September	23,635,974	18,415,866	5,220,108
October	19,498,751	13,078,141	6,420,610
November	29,369,656	21,563,827	7,805,829
December	36,574,423	26,709,698	9,864,725
Sub-Total	259,612,909	191,833,293	67,779,616

Kentucky Utilities Company and Louisville Gas and Electric Company
KIUC's Recommendation to Normalize Off-System Sales Margins
($)

	Intersystem Off-System Sales Revenues Monthly ECR Filings	Off-System Sales Cost of Fuel Monthly Fuel Filings	Off-System Sales Margins
Louisville Gas and Electric Company			
2006			
January	26,013,419	18,163,574	7,849,845
February	11,830,429	9,654,212	2,176,217
March	9,847,917	8,712,269	1,135,648
April	10,722,286	9,092,379	1,629,907
May	19,312,232	15,683,352	3,628,880
June	14,768,997	12,639,057	2,129,940
July	18,806,829	16,485,070	2,321,759
August	13,514,960	12,767,506	747,454
September	13,321,587	11,119,174	2,202,413
October	20,548,020	16,570,198	3,977,822
November	31,622,016	22,185,071	9,436,945
December	17,222,262	14,254,860	2,967,402
Sub-Total	207,530,954	167,326,722	40,204,232
Louisville Gas and Electric Company			
2007			
January	23,483,840	18,834,556	4,649,284
February	18,812,628	14,573,244	4,239,384
March	15,373,804	12,689,533	2,684,271
April	11,007,686	9,860,814	1,146,872
May	12,182,827	10,682,389	1,500,438
June	10,840,204	9,020,341	1,819,863
July	11,409,618	9,014,180	2,395,438
August	10,423,508	9,595,936	827,572
September	7,315,821	6,305,102	1,010,719
October	13,329,725	10,286,976	3,042,749
November	10,694,459	9,410,056	1,284,403
December	18,149,162	13,803,479	4,345,683
Sub-Total	163,023,282	134,076,606	28,946,676

Kentucky Utilities Company and Louisville Gas and Electric Company
KIUC's Recommendation to Normalize Off-System Sales Margins
($)

	Intersystem Off-System Sales Revenues Monthly ECR Filings	Off-System Sales Cost of Fuel Monthly Fuel Filings	Off-System Sales Margins
Louisville Gas and Electric Company			
2008			
January	20,067,916	16,511,669	3,556,247
February	11,770,651	9,965,155	1,805,496
March	17,765,119	14,048,383	3,716,736
April	12,296,562	9,646,803	2,649,759
May	20,330,264	14,965,918	5,364,346
June	17,816,390	13,615,793	4,200,597
July	16,137,160	12,223,124	3,914,036
August	12,002,698	10,140,367	1,862,331
September	20,935,942	15,880,631	5,055,311
October	29,950,665	24,479,840	5,470,825
November	34,409,142	26,551,439	7,857,703
December	25,147,168	21,064,159	4,083,009
Sub-Total	238,629,677	189,093,281	49,536,396
Louisville Gas and Electric Company			
2009			
January	16,906,124	15,093,188	1,812,936
February	13,111,973	12,625,978	485,995
March	14,156,392	12,842,285	1,314,107
April	11,572,181	11,281,939	290,242
May	14,535,213	13,568,103	967,110
June	7,917,583	7,473,176	444,407
July	7,698,609	7,591,328	107,281
August	6,731,611	6,634,886	96,725
September	7,998,118	7,855,680	142,438
October	9,284,929	8,666,724	618,205

EXHIBIT ____ (LK-5)

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 1, 2010

Question No. 40

Responding Witness: Paul W. Thompson/Shannon L. Charnas

Q-40. Refer to page 8 lines 14-18 of Mr. Thompson's Direct Testimony.

a. Please provide KU's share of the EEI income for each of the last five calendar years and the twelve months ending October 2009.

b. Provide the account to which KU books its share of the EEI income.

A-40. a. KU's share of the EEI income was as follows:

2005	$ 2,256,843
2006	$29,405,773
2007	$26,358,781
2008	$29,548,519
Test Year Ended	
10/31/09	$ 2,854,702
2009	$ 765,782

b. The earnings are recorded to the FERC account 418, other income.

EXHIBIT ____ (LK-6)

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 1, 2010

Question No. 61

Responding Witness: Shannon L. Charnas

Q-61. Refer to the Company's response to Staff 1-2 in which the Company identified an affiliate relationship with Electric Energy, Inc. ("EEI").

a. Please provide a detailed description of EEI.

b. Please provide a history by year of annual EEI dividends to the Company both before tax and after tax, by FERC account since the Company first invested in EEI.

c. Please provide the EEI dividends to the Company during the test year both before tax and after tax, by FERC account.

d. Please provide a history by year of the income statement effect of the EEI dividends to the Company both before tax and after tax, if any, by FERC account since the Company first invested in EEI.

e. Please provide the test year income statement effect of the EEI dividends to the Company both before tax and after tax, if any, by FERC account.

f. Please provide a history of annual EEI earnings included on the Company's income statement both before tax and after tax, if any, by FERC account since the Company first invested in EEI.

g. Please provide the test year income statement effect of the EEI earnings included on the Company's income statement both before and after tax, if any, by FERC account.

h. Please refer to the Attachment to Response to AG-1 Question No. 34, Page 3 of 20 from KU Case No. 2008-00251 in which KU provided a schedule entitled "Rollforward of Investment in EEI." Please provide a similar "Rollforward" schedule for the Company's EEI Investment through the end of the test year ended October 31, 2009.

i. Please provide a history by year of the Company's investment in EEI since the Company first invested in EEI.

j. Please provide a history of the Company's investment in EEI from December 31, 2008 through October 31, 2009.

A-61. a. KU is a minority shareholder (i.e., owns 20% of the common stock of EEI, which owns and operates a 1,000-Mw generating station in southern Illinois. Previously, KU had a contractual right to take 20% of the available capacity of the station under a pricing formula comparable to the cost of other power generated by KU. This contract governing the purchases from EEI terminated on December 31, 2005 on its own terms. Subsequent to December 31, 2005, EEI has sold power under general market-based pricing and terms. KU has not contracted with EEI for power under the new arrangements, but maintains its 20% ownership in the common stock of EEI.

KU is not the primary beneficiary of EEI, and, therefore, it is not consolidated into the financial statements of KU. EEI is accounted for under the equity method of accounting.

b. Dividends are recorded in account 216.1.

Dividends from EEI*

Year	Dividends*
1996	$ 2,460,420
1997	2,443,622
1998	2,168,058
1999	2,366,775
2000	2,312,037
2001	2,060,553
2002	1,585,021
2003	-
2004	-
2005	-
2006	27,500,000
2007	21,400,000
2008	30,000,000
October 31, 2009 – Year to Date	10,850,000

* Data provided is through the end of the test year and the thirteen years previous that was readily available. Dividends are accounted for as a reduction to undistributed earnings and are not shown net of tax.

c. KU recorded $18,350,000 in dividends for the 12 months ended October 31, 2009. Dividends are accounted for as a reduction to undistributed earnings and are not shown net of tax. All dividends were recorded in account 216.1.

d. KU's investment in EEI is accounted for using the equity method of accounting, therefore there is no income statement effect from EEI dividends.

e. See response to (d.) above.

EXHIBIT ____ (LK-7)

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 1, 2010

Question No. 62

Responding Witness: S. Bradford Rives

Q-62. Refer to Mr. Rives' Exhibit 2.

a. Please list all amounts by subsidiary and by year included in the undistributed subsidiary earnings in column 4 on these exhibits.

b. Please list all amounts by subsidiary and by year included in the undistributed subsidiary earnings in column 5 on these exhibits.

c. Please indicate whether the amounts in column 5 represent only direct investment or also include the earnings from EEI booked below the line.

d. Please provide the earnings by year from EEI booked below the line.

A-62. a. The entire amount in column 4 is the balance in undistributed earnings associated with KU's investment in EEI reduced by the related deferred tax balance. See response to Question No. 61(h)

b. Column 5 includes the cost based equity investment in EEI of $1,295,800.

c. As stated in (b), column 5 includes the cost based equity investment in EEI of $1,295,800.

d. See response to Question No. 61(f).

EXHIBIT ____ (LK-8)

Kentucky Utilities Company
EEI Operating Income and Total Revenue Requirement Adjustment
Recommended by KIUC
For the Test Year Ended October 31, 2009

		Amounts
EEI Before Tax Earnings Recognized by KU During Test Year - Total Company	(1)	2,854,702
Kentucky Retail Jurisdictional Factor - From Exhibit 2 in Company's Filing		87.15%
EEI Before Tax Earnings Recognized by KU During Test Year - KY Retail		2,487,873
Rev Req Effect of Changes to Capitalization Related to Elimination of EEI Reductions	(2)	(972,821)
Total Revenue Requirement Reduction by Reflecting EEI as Utility Income		1,515,051

(1) See KU response to KIUC 1-40
(2) See Calculation of Capitalization Effects on Cost of Capital Exhibit Section V

EXHIBIT ____ (LK-9)

Kentucky Utilities Company
EEI Operating Income Adjustment Based on Normalization of Before Tax Earnings
Recommended by KIUC
For the Test Year Ended October 31, 2009

		Amounts
EEI Before Tax Earnings Recognized by KU During 2006	(1)	29,405,773
EEI Before Tax Earnings Recognized by KU During 2007	(1)	26,358,781
EEI Before Tax Earnings Recognized by KU During 2008	(1)	29,548,519
EEI Before Tax Earnings Recognized by KU During Test Year	(1)	2,854,702
EEI Average Before Tax Earnings Recognized by KU - Total Company		22,041,944
EEI Before Tax Earnings Recognized by KU During Test Year - Total Company	(1)	2,854,702
Additional EEI Before Tax Earnings Recognized by KU Due to Normalization-Total Company		19,187,242
Kentucky Retail Jurisdictional Factor - From Exhibit 2 in Company's Filing		87.15%
Additional EEI Before Tax Earnings Recognized by KU Due to Normalization-KY Retail		$ 16,721,681

(1) See KU response to KIUC 1-40

EXHIBIT ____ (LK-10)

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 1, 2010

Question No. 44

Responding Witness: Valerie L. Scott

Q-44. Refer to page 5 lines 1-7 of Ms. Charnas' Direct Testimony.

a. Please identify, describe and quantify all one-time implementation costs for the CCS that were expensed during the test year. Provide this information by FERC expense account to the extent it is available at this level of detail.

b. Does the Company agree that such one-time implementation costs are not recurring?

c. Please identify, describe and quantify all annual savings that will result from the implementation of the CCS. Provide all assumptions, data, computations and electronic spreadsheets with formulas intact.

d. Please identify and quantify the savings that were achieved from the implementation of the CCS during the test year. Provide all assumptions, data, computations and electronic spreadsheets with formulas intact.

e. Please describe the retirement of the previous application, the date it was retired, the plant account from which it was retired, the gross plant amount that was retired, and the net plant amount that was retired.

A-44. a. One-time implementation costs for CCS that were expensed during the test year were as follows:

Type of Cost	Account	Amount
Outside Services	910001	$ 1,256,656
Meals	426501	6,506
Meals	910001	26,388
Meals	921903	148
Employee Moving Expense	426501	3,380
Tuition Reimbursement	926001	4,985
Travel	910001	57,072
Travel	921903	206
Miscellaneous Expenses	910001	3,087
Miscellaneous Expenses	426501	180
Total		$ 1,358,608

b. While, the one-time implementation cost is non-recurring, on-going costs will exceed the costs incurred during the test period. See the responses to Question No. 44 (c) and (d) below.

c. A net reduction in expenses was not expected in the organization. Cost savings associated with the retirement of the mainframe computing platform are offset by the payment of license fees for the new software and support. Please see attached on CD in the folder titled Question No. 44.

d. A net reduction in expenses was not expected or realized during the test year in the Information Technology departmønts. Please see attached on CD in the folder titled Question No. 44.

e. Prior to the merger with LG&E in 1998, KU expensed software, including its original legacy system. Therefore, there was no gross or net plant amount to be retired related to the original legacy system. Beginning with the merger with LG&E in 1998, KU capitalized software assets, consistent with LG&E. Retirements of minor enhancements that were capitalized subsequent to 1998 occurred as the enhancements became fully depreciated.

EXHIBIT ____ (LK-11)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2009-00549

Response to First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated March 1, 2010

Question No. 42

Responding Witness: Valerie L. Scott

Q-42. Refer to page 5 lines 1-7 of Ms. Charnas' Direct Testimony.

a. Please identify, describe and quantify all one-time implementation costs for the CCS that were expensed during the test year. Provide this information by FERC expense account to the extent it is available at this level of detail.

b. Does the Company agree that such one-time implementation costs are not recurring?

c. Please identify, describe and quantify all annual savings that will result from the implementation of the CCS. Provide all assumptions, data, computations and electronic spreadsheets with formulas intact.

d. Please identify and quantify the savings that were achieved from the implementation of the CCS during the test year. Provide all assumptions, data, computations and electronic spreadsheets with formulas intact.

e. Please describe the retirement of the previous application, the date it was retired, the plant account from which it was retired, the gross plant amount that was retired, and the net plant amount that was retired.

A-42. a. One-time implementation costs for CCS that were expensed during the test year were as follows:

Type of Cost	Account	Amount
Outside Services	910001	$ 1,357,229
Meals	426501	6,506
Meals	910001	27,908
Employee Moving Expense	426501	3,662
Tuition Reimbursement	926001	3,207
Travel	910001	50,140
Miscellaneous Expenses	910001	4,994
Total		$ 1,453,646

b. While the one-time implementation cost is non-recurring, on-going costs will exceed the costs incurred during the test period. See the responses to Question No. 42 (c) and (d) below.

c. A net reduction in expenses was not expected in the organization. Cost savings associated with the retirement of the mainframe computing platform are offset by the payment of license fees for the new software and support. Please see attached on CD in the folder titled Question No. 42.

d. A net reduction in expenses was not expected or realized during the test year in the Information Technology departments. Please see attached on CD in the folder titled Question No. 42.

e. LG&E retires a software asset once it becomes fully depreciated in accordance with FERC guidelines on vintage year accounting. The original legacy system was retired from the plant records in 1999 and 2000 from plant account 303 – Intangible Plant with a gross plant amount of $14,749,650 and $5,497,388 respectively. The net plant amounts for these assets were $0 as they were fully depreciated. Retirements of minor enhancements subsequent to the in-service date occurred as the enhancements became fully depreciated.

EXHIBIT ____ (LK-12)

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 1, 2010

Question No. 45

Responding Witness: Ronald L. Miller

Q-45. Refer to page 2 line 10 through page 3 line 2 of Mr. Miller's Direct Testimony.

a. When will the Company recognize the coal tax credit for 2009 on its accounting books?

b. Please provide the amount of the coal tax credit for 2009 that will be recognized on the Company's accounting books in 2010, if any, separated into the portion used as a credit against the Kentucky state income tax and the portion used as a credit against property taxes.

c. Please confirm that the Company agrees that the coal tax credit to the Kentucky state income tax must be grossed-up to quantify the revenue requirement effect of either including or excluding this adjustment.

A-45. a. The Company will recognize the coal tax credit for 2009 on its accounting books in 2010.

b. The Company will recognize $5,555,186 of coal tax credit for 2009 and is expecting to use the entire amount as a credit against property taxes.

c. To the extent the coal tax credit is being used to reduce property taxes, the Company does not believe the coal tax credit must be grossed-up to quantify the revenue requirement effect of either including or excluding this adjustment.

EXHIBIT ____ (LK-13)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2009-00549

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 1, 2010

Question No. 44

Responding Witness: Ronald L. Miller

Q-44. Refer to page 2 line 11 through page 3 line 4 of Mr. Miller's Direct Testimony.

a. When will the Company recognize the coal tax credit for 2009 on its accounting books?

b. Please provide the amount of the coal tax credit for 2009 that will be recognized on the Company's accounting books in 2010, if any, separated into the portion used as a credit against the Kentucky state income tax and the portion used as a credit against property taxes.

c. Please confirm that there are two adjustments to remove the coal tax credit from the test year, the first for $976,551 shown on Exhibit 1 Schedule 1.38 and the second for $1,037,813 shown on Exhibit 1 Schedule 1.43.

d. Please confirm that the Company agrees that the coal tax credit to the Kentucky state income tax must be grossed-up to quantify the revenue requirement effect of either including or excluding this adjustment.

A-44. a. The Company will recognize the coal tax credit for 2009 on its accounting books in 2010.

b. The Company has applied for $3,534,596 of coal tax credit for 2009 and, if approved, is expecting to use the entire amount as a credit against property taxes.

c. Yes, the Company does have two adjustments to remove the coal tax credit from the test year. The first for $976,551 removes the coal tax credit applied to property tax expense. The second for $1,037,813 removes the coal tax credit applied to income tax expense.

d. To the extent that the coal tax credit is being used to reduce property taxes, the Company does not believe the coal tax credit must be grossed-up to quantify the revenue requirement effect of either including or excluding this adjustment.

EXHIBIT ____ (LK-14)

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 1, 2010

Question No. 46

Responding Witness: Ronald L. Miller

Q-46. Refer to page 3 lines 3-15 of Mr. Miller's Direct Testimony.

a. Please provide a copy of all studies, analyses, and/or all other documentation that addresses the availability of the $2 per ton credit for eligible Kentucky coal purchases for new clean coal facilities.

b. Please provide a copy of all applications and/or other correspondence with any state agency addressing the availability and/or amount of the $2 per ton credit for eligible Kentucky coal purchases for new clean coal facilities.

c. Please indicate whether the Company is aware of any reason why it would not obtain the $2 per ton credit for eligible Kentucky coal purchases for new clean coal facilities.

A-46. a. There are presently no internal studies, analyses, or other documentation by the Company addressing the availability of the credit. Attached is a copy of the Kentucky Revised Statute – KRS § 141.428 Kentucky Clean Coal Incentive Act.

b. The Company has not filed an application for the Kentucky Clean Coal Incentive tax credit. The Company has made informal inquiries with state representatives regarding the certification process. Based on these inquiries, we believe there have been no other applicants for this credit, and consequently, no certification process is in place. We were invited to formally contact the state to determine eligibility and plan to do so prior to Trimble County 2 going in service in mid 2010.

c. As discussed in (b) above, there is currently no established qualification criteria or procedures for certification. Due to this uncertainty, the Company is unsure at this time whether it will be eligible for the credit.

<u>KRS § 141.428</u>

141.428 Kentucky Clean Coal Incentive Act; definitions; tax credit; administrative regulations

(1) As used in this section:

(a) "Clean coal facility" means an electric generation facility beginning commercial operation on or after January 1, 2005, at a cost greater than one hundred fifty million dollars ($150,000,000) that is located in the Commonwealth of Kentucky and is certified by the Environmental and Public Protection Cabinet as reducing emissions of pollutants released during generation of electricity through the use of clean coal equipment and technologies;

(b) "Clean coal equipment" means equipment purchased and installed for commercial use in a clean coal facility to aid in reducing the level of pollutants released during the generation of electricity from eligible coal;

(c) "Clean coal technologies" means technologies incorporated for use within a clean coal facility to lower emissions of pollutants released during the generation of electricity from eligible coal;

(d) "Eligible coal" means coal that is subject to the tax imposed under KRS 143.020;

(e) "Ton" means a unit of weight equivalent to two thousand (2,000) pounds; and

(f) "Taxpayer" means taxpayer as defined in KRS 131.010(4).

(2) Effective for tax years ending on or after December 31, 2006, a nonrefundable, nontransferable credit shall be allowed for:

(a) Any electric power company subject to tax under KRS 136.120 and certified as a clean coal facility or any taxpayer that owns or operates a clean coal facility and purchases eligible coal that is used by the taxpayer in a certified clean coal facility; or

(b) A parent company of an entity identified in paragraph (a) of this subsection if the subsidiary is wholly owned.

(3) (a) The credit may be taken against the taxes imposed by:

1. KRS 136.070;

2. KRS 136.120; or

3. KRS 141.020 or 141.040, and 141.0401.

(b) The credit shall not be carried forward and must be used on the tax return filed for the period during which the eligible coal was purchased. The Environmental and Public Protection Cabinet must approve and certify use of the clean coal equipment and technologies within a clean coal facility before any taxpayer may claim the credit.

(c) The credit allowed under paragraph (a) of this subsection shall be applied both to the income tax imposed under KRS 141.020 or 141.040 and to the limited liability entity tax imposed under KRS 141.0401, with the ordering of credits as provided in KRS 141.0205.

(4) The amount of the allowable credit shall be two dollars ($2) per ton of eligible coal purchased that is used to generate electric power at a certified clean coal facility, except that no credit shall be allowed if the eligible coal has been used to generate a credit under KRS 141.0405 for the taxpayer, a parent, or a subsidiary.

(5) Each taxpayer eligible for the credit provided under subsection (2) of this section shall file a clean coal incentive credit claim on forms prescribed by the Department of Revenue. At the time of filing for the credit, the taxpayer shall submit an electronic report verifying the tons of coal subject to the tax imposed by KRS 143.020 purchased for each year in which the credit is claimed. The Department of Revenue shall determine the amount of the approved credit and issue a credit certificate to the taxpayer.

(6) Corporations and pass-through entities subject to the tax imposed under KRS 141.040 or 141.0401 shall be eligible to apply, subject to the conditions imposed under this section, the approved credit against its liability for the taxes, in consecutive order as follows:

(a) The credit shall first be applied against both the tax imposed by KRS 141.0401 and the tax imposed by KRS 141.020 or 141.040, with the ordering of credits as provided in KRS 141.0205;

(b) The credit shall then be applied to the tax imposed by KRS 136.120.

The credit shall meet the entirety of the taxpayer's liability under the first tax listed in consecutive order before applying any remaining credit to the next tax listed. The taxpayer's total liability under each preceding tax must be fully met before the remaining credit can be applied to the subsequent tax listed in consecutive order.

(7) If the taxpayer is a pass-through entity not subject to tax under KRS 141.040, the amount of approved credit shall be applied against the tax imposed by KRS 141.0401 at the entity level, and shall also be distributed to each partner, member, or shareholder based on the partner's, member's, or shareholder's distributive share of the income of the pass-through entity. The credit shall be claimed in the same manner as specified in subsection (6) of this section. Each pass-through entity shall notify the Department of Revenue electronically of all partners, members, or shareholders who may claim any amount of the approved credit. Failure to provide information to the Department of

Revenue in a manner prescribed by regulation may constitute the forfeiture of available credits to all partners, members, or shareholders associated with the pass-through entity.

(8) The taxpayer shall maintain all records associated with the credit for a period of five (5) years. Acceptable verification of eligible coal purchased shall include invoices that indicate the tons of eligible coal purchased from a Kentucky supplier of coal and proof of remittance for that purchase.

(9) The Department of Revenue shall develop the forms required under this section, specifying the procedure for claiming the credit, and applying the credit against the taxpayer's liability in the order provided under subsections (6) and (7) of this section.

(10) The Governor's Office of Energy Policy, Environmental and Public Protection Cabinet, and the Department of Revenue shall promulgate administrative regulations necessary to administer this section.

(11) This section shall be known as the Kentucky Clean Coal Incentive Act.

HISTORY: 2007 2nd ex s, c 1, § 28, eff. 8-30-07; 2006 1st ex s, c 2, § 35, eff. 6-28-06; 2005 c 168, § 142, eff. 3-18-05

Legislative Research Commission Note (6-28-06): 2006 (1st Extra. Sess.) Ky. Acts ch. 2, sec. 73, provides that "unless a provision of this Act specifically applies to an earlier tax year, the provisions of this Act shall apply to taxable years beginning on or after January 1, 2007."

Legislative Research Commission Note (3-18-05): 2005 Ky. Acts ch. 168, sec. 165, provides that this section shall apply to tax years beginning on or after January 1, 2005.

Legislative Research Commission Note (3-18-05): 2005 Ky. Acts chs. 11, 85, 95, 97, 98, 99, 123, and 181 instruct the Reviser of Statutes to correct statutory references to agencies and officers whose names have been changed in 2005 legislation confirming the reorganization of the executive branch. Such a correction has been made in this section.

EXHIBIT ____ (LK-15)

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 26, 2010

Question No. 11

Responding Witness: Paul W. Thompson/Ronald L. Miller

Q-11. Refer to the Company's response to KIUC 1-46.

a. Is there any reason the Company believes that it will not qualify for the $2 per ton credit for eligible Kentucky coal purchases for new clean coal facilities?

b. Will the coal used at TC2 be subject to the tax imposed under KRS 143.020 as referenced in KRS 141.428(1)(d)? If not, please explain why it will not be.

c. Is the Company or its parent subject to tax under KRS 136.120 as referenced in KRS 141.428(2)(a) and (b)? If not, please explain why it will not be.

d. Please describe the taxes imposed by: i) KRS 136.070, ii) KRS 136.120, and iii) KRS 141.020 or 141.040, and 141.041 as referenced in KRS 141.428(3)(a).

e. To the extent the Company qualifies for the $2 per ton credit for eligible Kentucky coal purchases for new clean coal facilities and the credit is applied to reduce the Company's Kentucky state income tax, please confirm that the Company agrees that the revenue requirement effect is the amount of the credit grossed-up for income taxes. If the Company does not agree with this statement, then please explain why it disagrees and provide a copy of all research and/or source documents upon which it relies for such disagreement.

f. Please provide the number of tons of coal that the Company will burn at TC2 at an 85% assumed capacity factor. Please provide all assumptions necessary to replicate the Company's quantification.

g. Please provide the Btu content of the coal that the Company will burn at TC2.

h. Please provide the projected heat rate of TC2.

A-11. a. As stated in the response to KIUC 1-46 b and c, the Kentucky Department of Energy and Environment has not formulated the qualification criteria or procedures for certification. Without knowing the criteria and procedures, qualification is not known at this time.

b. KRS 143.020 imposes a tax on the severance and/or processing of coal in the state of Kentucky. KU expects that Kentucky sourced coal used at TC2 will be subject to the severance tax imposed under KRS 143.020. The remaining coal purchased will originate outside of Kentucky and will not be subject to the tax imposed under KRS 143.020.

c. Yes, KU is subject to tax under KRS 136.120 which imposes state property taxes on operating property of public service corporations, including gas and electric power companies.

d. i) KRS 136.070 imposed a corporation license tax on corporations either having a commercial domicile in this state or foreign corporations owning or leasing property within the State of Kentucky. This tax ended for tax periods ending on 12/31/05 and later. As a public service corporation KU was not subject to the tax under KRS 136.070 prior to its expiration under KRS 136.0701.

ii) KRS 136.120 imposes state property taxes on operating property for public service corporations, including gas and electric power companies. KU is a public service corporation that is centrally assessed property taxes under KRS 136.120.

iii) KRS 141.020 is the imposition of Kentucky state income taxes on individuals. KRS 141.040 is the imposition of Kentucky income taxes on corporations. KRS 141.041 is the imposition of Kentucky limited liability entity taxes. KU is subject to KRS 141.040.

e. If KU receives the new clean coal incentive tax credit and if the credit were applied to reduce Kentucky income taxes, the revenue requirement effect of the state credit (less the loss of applicable federal tax benefit) would be grossed up for income taxes. However, KU has not applied for nor received the new clean coal incentive tax credit.

f. The Company does <u>not</u> anticipate operating TC2 at an 85% capacity factor, particularly in the first year of operation. The tons burned for total Trimble County 2 at an 85% capacity factor is estimated at 2,500,000 per year. That is based on 6,942 MMBTU per hour, an 85% capacity factor, and a BTU content per pound of 10,340. Therefore the BTU calculation is 6,942 X 24 hours X 365 days X 85% Capacity Factor X 1,000,000 = 51,690,132,000,000 BTU's.

BTU's per ton = 10,340 BTU's per pound X 2000 pounds = 20,680,000.

Tons per year = 51,690,132,000,000 divided by 20,680,000 = approx. 2,500,000.

Tons Calculated Above	2,500,000
Adjustment for 25% IMEA/IMPA ownership	0.75
KU/LG&E ownership tons	1,875,000
KU ownership percentage	0.81
KU tons	1,518,750
Estimated Kentucky Purchases	0.53
KU Kentucky purchases	804,938

g. The expected BTU content of the coal is 10,340 BTU per Pound.

h. The projected average net heat rate for the unit is 8,774 (BTU/kWh) for the year 2010, and 8,753 (BTU/kWh) for the year 2011.

EXHIBIT ____ (LK-16)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2009-00549

**Response to First Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 26, 2010**

Question No. 8

Responding Witness: Paul W. Thompson/Ronald L. Miller

Q-8. Refer to the Company's response to KIUC 1-45.

a. Is there any reason the Company believes that it will not qualify for the $2 per ton credit for eligible Kentucky coal purchases for new clean coal facilities?

b. Will the coal used at TC2 be subject to the tax imposed under KRS 143.020 as referenced in KRS 141.428(1)(d)? If not, please explain why it will not be.

c. Is the Company or its parent subject to tax under KRS 136.120 as referenced in KRS 141.428(2)(a) and (b)? If not, please explain why it will not be.

d. Please describe the taxes imposed by: i) KRS 136.070, ii) KRS 136.120, and iii) KRS 141.020 or 141.040, and 141.041 as referenced in KRS 141.428(3)(a).

e. To the extent the Company qualifies for the $2 per ton credit for eligible Kentucky coal purchases for new clean coal facilities and the credit is applied to reduce the Company's Kentucky state income tax, please confirm that the Company agrees that the revenue requirement effect is the amount of the credit grossed-up for income taxes. If the Company does not agree with this statement, then please explain why it disagrees and provide a copy of all research and/or source documents upon which it relies for such disagreement.

f. Please provide the number of tons of coal that the Company will burn at TC2 at an 85% assumed capacity factor. Please provide all assumptions necessary to replicate the Company's quantification.

g. Please provide the Btu content of the coal that the Company will burn at TC2.

h. Please provide the projected heat rate of TC2.

A-8. a. As stated in the response to KIUC 1-45 b and c, the Kentucky Department of Energy and Environment has not formulated the qualification criteria or procedures for certification. Without knowing the criteria and procedures, qualification is not known at this time.

b. KRS 143.020 imposes a tax on the severance and/or processing of coal in the state of Kentucky. LG&E expects that Kentucky sourced coal used at TC2 will be subject to the severance tax imposed under KRS 143.020. The remaining coal purchased will originate outside of Kentucky and will not be subject to the tax imposed under KRS 143.020.

c. Yes, LG&E is subject to tax under KRS 136.120 which imposes state property taxes on operating property of public service corporations, including gas and electric power companies.

d. i) KRS 136.070 imposed a corporation license tax on corporations either having a commercial domicile in this state or foreign corporations owning or leasing property within the State of Kentucky. This tax ended for tax periods ending on 12/31/05 and later. As a public service corporation LG&E was not subject to the tax under KRS 136.070 prior to its expiration under KRS 136.0701.

ii) KRS 136.120 imposes state property taxes on operating property for public service corporations, including gas and electric power companies. LG&E is a public service corporation that is centrally assessed property taxes under KRS 136.120.

iii) KRS 141.020 is the imposition of Kentucky state income taxes on individuals. KRS 141.040 is the imposition of Kentucky income taxes on corporations. KRS 141.041 is the imposition of Kentucky limited liability entity taxes. LG&E is subject to KRS 141.040.

e. If LG&E receives the new clean coal incentive tax credit and if the credit were applied to reduce Kentucky income taxes, the revenue requirement effect of the state credit (less the loss of applicable federal tax benefit) would be grossed up for income taxes. However, LG&E has not applied for nor received the new clean coal incentive tax credit.

f. The Company does <u>not</u> anticipate operating TC2 at an 85% capacity factor, particularly in the first year of operation. The tons burned for total Trimble County 2 at an 85% capacity factor is estimated at 2,500,000 per year. That is based on 6,942 MMBTU per hour, an 85% capacity factor, and a BTU content per pound of 10,340. Therefore the BTU calculation is 6,942 X 24 hours X 365 days X 85% Capacity Factor X 1,000,000 = 51,690,132,000,000 BTU's.

BTU's per ton = 10,340 BTU's per pound X 2000 pounds = 20,680,000.

Tons per year = 51,690,132,000,000 divided by 20,680,000 = approx. 2,500,000.

Tons Calculated Above	2,500,000
Adjustment for 25% IMEA/IMPA ownership	0.75
KU/LG&E ownership tons	1,875,000
LG&E ownership percentage	0.19
LG&E tons	356,250
Estimated Kentucky Purchases	0.53
LG&E Kentucky purchases	188,813

g. The expected BTU content of the coal is 10,340 BTU per Pound.

h. The projected average net heat rate for the unit is 8,774 (BTU/kWh) for the year 2010, and 8,753 (BTU/kWh) for the year 2011.

EXHIBIT ____ (LK-17)

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 1, 2010

Question No. 48

Responding Witness: Daniel K. Arbough

Q-48. Please provide a five year monthly history (2005-2009) of the average daily balances of short term debt by type of short term debt security and/or source (bank loans, commercial paper, money pool, receivables financing, etc.), the average interest rate for each month by type of short term debt and/or source, and the basis for the interest rate for each month by type of short term debt and/or source.

A-48. Attached is a five year monthly history (2005-2009) of the average daily balances of short term debt. During this period Kentucky Utilities Company's short-term debt has been sourced through a Money Pool agreement. The daily outstanding balance of all short term loans accrues interest at the rate for high-grade unsecured 30-day commercial paper of major corporations sold through dealers as quoted in The Wall Street Journal (the "Average Composite") on the last business day of the prior calendar month.

Month/Year	Average Daily Balance	Average Interest Rate
January-05	$26,587,187.50	2.340%
February-05	$22,377,241.38	2.500%
March-05	$7,465,312.50	2.650%
April-05	$8,442,741.94	2.780%
May-05	$8,318,593.75	2.980%
June-05	$62,021,129.03	3.060%
July-05	$40,323,750.00	3.270%
August-05	$12,323,125.00	3.430%
September-05	$10,620,967.74	3.640%
October-05	$21,761,406.25	3.790%
November-05	$52,720,645.16	4.030%
December-05	$57,655,781.25	4.210%
January-06	$117,075,000.00	4.300%
February-06	$92,364,689.66	4.510%
March-06	$34,955,468.75	4.530%
April-06	$64,977,838.71	4.780%
May-06	$63,522,687.50	4.960%
June-06	$80,722,677.42	5.010%
July-06	$42,036,445.44	5.290%
August-06	$52,230,410.25	5.360%
September-06	$42,255,015.29	5.270%
October-06	$28,569,991.50	5.260%
November-06	$23,754,924.97	5.270%
December-06	$55,844,272.75	5.250%
January-07	$76,576,024.59	5.270%
February-07	$67,629,674.69	5.260%
March-07	$66,906,116.50	5.260%
April-07	$34,358,505.61	5.260%
May-07	$89,762,741.50	5.260%
June-07	$126,776,634.65	5.260%
July-07	$149,287,272.75	5.280%
August-07	$193,959,429.00	5.240%
September-07	$169,563,279.81	5.620%
October-07	$85,925,304.00	5.050%
November-07	$55,212,020.67	4.720%
December-07	$73,478,760.25	4.750%
January-08	$25,431,034.65	4.980%
February-08	$34,988,292.71	3.080%
March-08	$43,500,047.75	3.080%
April-08	$51,952,034.65	2.630%
May-08	$79,860,329.00	2.840%
June-08	$73,191,389.48	2.430%
July-08	$102,288,454.00	2.450%

August-08	$132,249,735.25	2.440%
September-08	$114,129,099.16	2.450%
October-08	$97,178,922.75	4.950%
November-08	$118,573,099.16	2.950%
December-08	$83,309,297.75	1.490%
January-09	$14,894,563.38	0.5400%
February-09	$13,612,087.33	0.7900%
March-09	$16,073,469.15	0.7500%
April-09	$27,064,244.32	0.5500%
May-09	$53,960,235.25	0.4000%
June-09	$80,707,212.06	0.3000%
July-09	$39,338,391.50	0.3500%
August-09	($478,108.50)	0.3000%
September-09	($207,433.10)	0.2500%
October-09	$5,872,891.50	0.2200%
November-09	$8,062,566.90	0.2200%
December-09	$8,815,654.00	0.2000%

EXHIBIT ____ (LK-18)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2009-00549

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 1, 2010

Question No. 47

Responding Witness: Daniel K. Arbough

Q-47. Please provide a five year monthly history (2005-2009) of the average daily balances of short term debt by type of short term debt security and/or source (bank loans, commercial paper, money pool, receivables financing, etc.), the average interest rate for each month by type of short term debt and/or source, and the basis for the interest rate for each month by type of short term debt and/or source.

A-47. Attached is a five year monthly history (2005-2009) of the average daily balances of short term debt. During this period Louisville Gas and Electric Company's short-term debt has been sourced through a Money Pool agreement. The daily outstanding balance of all short term loans accrues interest at the rate for high-grade unsecured 30-day commercial paper of major corporations sold through dealers as quoted in The Wall Street Journal (the "Average Composite") on the last business day of the prior calendar month.

Month/Year	Average Daily Balance	Average Interest Rate
January-05	$82,890,312.50	2.340%
February-05	$73,938,103.45	2.500%
March-05	$36,421,250.00	2.650%
April-05	$13,063,225.81	2.780%
May-05	($20,831,423.88)	2.980%
June-05	$7,725,967.74	3.060%
July-05	$14,120,625.00	3.270%
August-05	$40,592,031.25	3.430%
September-05	$40,668,387.10	3.640%
October-05	$51,104,531.25	3.790%
November-05	$113,880,000.00	4.030%
December-05	$138,556,406.25	4.210%
January-06	$117,075,000.00	4.300%
February-06	$87,038,103.45	4.510%
March-06	$34,955,468.75	4.530%
April-06	$19,669,032.26	4.780%
May-06	$3,392,656.25	4.960%
June-06	($7,751,290.32)	5.010%
July-06	($6,455,875.00)	5.290%
August-06	($6,227,906.25)	5.360%
September-06	($1,438,838.71)	5.270%
October-06	$17,384,972.99	5.260%
November-06	$74,173,290.32	5.270%
December-06	$60,547,696.97	5.250%
January-07	$54,965,454.55	5.270%
February-07	$60,032,482.76	5.260%
March-07	$17,797,593.75	5.260%
April-07	$7,963,903.23	5.260%
May-07	$20,492,218.75	5.260%
June-07	$42,097,000.00	5.260%
July-07	$79,112,750.00	5.280%
August-07	$82,031,156.25	5.240%
September-07	$76,146,580.65	5.620%
October-07	$91,862,437.50	5.050%
November-07	$100,511,774.19	4.720%
December-07	$71,306,306.25	4.750%
January-08	$62,527,887.50	4.980%
February-08	$42,261,909.68	3.080%
March-08	$38,754,262.50	3.080%
April-08	$138,886,262.50	2.630%
May-08	$160,865,606.25	2.840%
June-08	$172,720,941.94	2.430%
July-08	$266,829,512.50	2.450%

August-08	$308,515,950.00	2.440%
September-08	$320,625,264.52	2.450%
October-08	$330,075,012.50	4.950%
November-08	$324,371,458.06	2.950%
December-08	$220,673,387.50	1.490%
January-09	$203,853,681.25	0.5400%
February-09	$158,085,779.31	0.7900%
March-09	$115,697,806.25	0.7500%
April-09	$122,559,077.42	0.5500%
May-09	$115,686,212.50	0.4000%
June-09	$103,614,754.84	0.3000%
July-09	$147,595,931.25	0.3500%
August-09	$155,036,462.50	0.3000%
September-09	$143,386,270.97	0.2500%
October-09	$143,327,993.75	0.2200%
November-09	$144,216,980.65	0.2200%
December-09	$157,782,806.25	0.2000%

EXHIBIT ____ (LK-19)

KIUC Adjustments to KU Capitalization and Cost of Capital
Test Year Ending 10/31/2009

I. KU Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Per Filing

	Per Book Balance	KU Proforma Adjustments	KU Adjusted Capitalization	KU Kentucky Jurisdictional Factor	KU Kentucky Adjusted Capitalization	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement
Short Term Debt	19,665,954	(403,916)	19,262,038	87.15%	16,786,866	0.55%	0.22%	0.00%	0.00%	-
Long Term Debt	1,631,779,405	(33,525,319)	1,598,254,086	87.15%	1,392,878,436	45.60%	4.68%	2.13%	2.14%	65,345,247
Common Equity	1,933,128,508	(45,717,931)	1,887,410,577	87.15%	1,644,878,318	53.85%	11.50%	6.19%	9.86%	301,035,751
Total Capital	3,584,573,867	(79,647,166)	3,504,926,701		3,054,543,620	100.00%		8.32%	11.99%	366,380,997

II. KU Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization for:
Capitalization Adjustment 1 - Reflect Average Short Term Debt

	KU Adjusted Capitalization	KIUC Proforma Adjustment 1	KIUC Adjusted Capitalization After Adjustment 1	Kentucky Jurisdictional Factor	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	19,262,038	18,060,708	37,322,746	87.15%	32,526,773	1.06%	0.22%	0.00%	0.00%	71,880	71,880
Long Term Debt	1,598,254,086	(8,281,233)	1,589,972,853	87.15%	1,385,661,341	45.36%	4.68%	2.12%	2.13%	65,131,479	(213,768)
Common Equity	1,887,410,577	(9,779,475)	1,877,631,102	87.15%	1,636,355,506	53.57%	11.50%	6.16%	9.81%	299,610,183	(1,425,567)
Total Capital	3,504,926,701	-	3,504,926,701		3,054,543,620	100.00%		8.29%	11.94%	364,813,542	(1,567,455)

III. KU Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Short Term Debt Rate to 0.20% and the Long Term Debt Rate to 4.66%.

	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	32,526,773	1.06%	0.20%	0.00%	0.00%	65,345	(6,535)
Long Term Debt	1,385,661,341	45.36%	4.66%	2.11%	2.12%	64,853,163	(278,316)
Common Equity	1,636,355,506	53.57%	11.50%	6.16%	9.81%	299,610,183	-
Total Capital	3,054,543,620	100.00%		8.28%	11.93%	364,528,692	(284,850)

KIUC Adjustments to KU Capitalization and Cost of Capital
Test Year Ending 10/31/2009

IV. KU Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Return on Common Equity to 9.7%.

	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	32,526,773	1.06%	0.20%	0.00%	0.00%	65,345	-
Long Term Debt	1,385,661,341	45.36%	4.66%	2.11%	2.12%	64,853,163	-
Common Equity	1,636,355,506	53.57%	9.70%	5.20%	8.27%	252,714,698	(46,895,485)
Total Capital	3,054,543,620	100.00%		7.31%	10.40%	317,633,207	(46,895,485)

V. KU Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization For:
Capitalization Adjustment 2 - Eliminate Company's Adjustments to Remove its Original EEI Investment and Undistributed EEI Earnings

	KIUC Adjusted Capitalization After Adjustment 1	KIUC Proforma Adjustment 2	KIUC Adjusted Capitalization After Adjustment 2	Kentucky Jurisdictional Factor	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	37,322,746	7,127	37,329,873	87.15%	32,532,985	1.06%	0.20%	0.00%	0.00%	65,362	17
Long Term Debt	1,589,972,853	589,848	1,590,562,701	87.15%	1,386,175,394	45.28%	4.66%	2.11%	2.12%	64,877,208	24,045
Common Equity	1,877,631,102	6,906,683	1,884,537,785	87.15%	1,642,374,680	53.65%	9.70%	5.20%	8.29%	253,644,261	929,563
Total Capital	3,504,926,701	7,503,658	3,512,430,359		3,061,083,058	100.00%		7.32%	10.41%	318,586,831	953,625

EXHIBIT ____ (LK-20)

KIUC Adjustments to LG&E Capitalization and Cost of Capital
Test Year Ending 10/31/2009

I. LG&E Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Per Filing

	Per Book Balance	LG&E Proforma Adjustments	LG&E Adjusted Capitalization	LG&E Kentucky Jurisdictional Factor	LG&E Kentucky Adjusted Capitalization	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement
Short Term Debt	150,667,400	(150,667,400)	-	79.62%	-	0.00%	0.22%	0.00%	0.00%	-
Long Term Debt	896,104,000	150,261,828	1,046,365,828	79.62%	833,116,472	46.14%	4.61%	2.13%	2.14%	38,644,783
Common Equity	1,237,876,536	(16,229,595)	1,221,646,941	79.62%	972,675,294	53.86%	11.50%	6.19%	9.90%	178,782,917
Total Capital	2,284,647,936	(16,635,167)	2,268,012,769		1,805,791,767	100.00%		8.32%	12.04%	217,427,699

II. LG&E Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization for:
Capitalization Adjustment 1 - Reflect Average Short Term Debt

	LG&E Adjusted Capitalization	KIUC Proforma Adjustment 1	KIUC Adjusted Capitalization After Adjustment 1	Kentucky Jurisdictional Factor	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	-	100,000,000	100,000,000	79.62%	79,620,000	4.41%	0.22%	0.01%	0.01%	175,988	175,988
Long Term Debt	1,046,365,828	(46,135,800)	1,000,230,028	79.62%	796,383,149	44.10%	4.61%	2.03%	2.04%	36,886,427	(1,758,356)
Common Equity	1,221,646,941	(53,864,200)	1,167,782,741	79.62%	929,788,618	51.49%	11.50%	5.92%	9.47%	171,021,139	(7,761,778)
Total Capital	2,268,012,769	-	2,268,012,769		1,805,791,767	100.00%		7.96%	11.52%	208,083,553	(9,344,146)

III. LG&E Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Short Term Debt Rate to 0.20% and the Long Term Debt Rate to 4.58%.

	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	79,620,000	4.41%	0.20%	0.01%	0.01%	159,986	(16,002)
Long Term Debt	796,383,149	44.10%	4.58%	2.02%	2.03%	36,646,394	(240,033)
Common Equity	929,788,618	51.49%	11.50%	5.92%	9.47%	171,021,139	-
Total Capital	1,805,791,767	100.00%		7.95%	11.51%	207,827,518	(256,035)

KIUC Adjustments to LG&E Capitalization and Cost of Capital
Test Year Ending 10/31/2009

IV. LG&E Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Return on Common Equity to 9.7%.

	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	79,620,000	4.41%	0.20%	0.01%	0.01%	159,986	-
Long Term Debt	796,383,149	44.10%	4.58%	2.02%	2.03%	36,646,394	-
Common Equity	929,788,618	51.49%	9.70%	4.99%	7.99%	144,252,599	(26,768,539)
Total Capital	1,805,791,767	100.00%		7.02%	10.03%	181,058,979	(26,768,539)

EXHIBIT ____ (LK-21)

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

UPDATED Response to First Data Request of Commission Staff
Dated January 19, 2010

Updated Response filed March 31, 2010

Question No. 43

Responding Witness: S. Bradford Rives

Q-43. Provide any information, when known, that would have a material effect on net operating income, rate base, or cost of capital that has occurred after the test year but were not incorporated in the filed testimony and exhibits.

A-43. See attached Updated Rives Exhibit 2 and Analysis of the Embedded Cost of Capital, reflecting changes to embedded cost of capital through February 28, 2010.

KENTUCKY UTILITIES

Capitalization at October 31, 2009
with Annual Cost Rate as of February 28, 2010

		Per Books 10-31-09 (1)	Capital Structure (2)	Trimble County Joint Use Assets Transfer (3)	Undistributed Subsidiary Earnings (4)	Investment in EEI (Col 2 x Col 5 Line 4) (5)	Investments in OVEC and Other (Col 2 x Col 6 Line 4) (6)	Adjustments to Total Co Capitalization (Sum of Col 3 - Col 6) (7)	Adjusted Total Company Capitalization (Col 1 - Col 7) (8)	Jurisdictional Rate Base Percentage (Exhibit 3 Line 19) (9)	Kentucky Jurisdictional Capitalization (Col 8 x Col 9) (10)
1	Short Term Debt	$ 19,665,954	0.55%	$ 266,095	$ -	$ (7,127)	$ (4,621)	$ 254,347	$ 19,920,301	87.15%	$ 17,360,542
2	Long Term Debt	1,631,779,405	45.52%	22,022,972	-	(589,848)	(382,487)	21,050,637	1,652,830,042	87.15%	1,440,441,382
3	Common Equity	1,933,128,508	53.93%	26,091,802	(6,207,858)	(698,825)	(453,153)	18,731,966	1,951,860,471	87.15%	1,701,046,402
4	Total Capitalization	$ 3,584,573,867	100.00%	$ 48,380,869	$ (6,207,858)	$ (1,295,800)	$ (840,261)	$ 40,036,950	$ 3,624,610,816		$ 3,158,848,326

		Kentucky Jurisdictional Capitalization (10)	Capital Structure (11)	Environmental Compliance Plans (a) (Col 11 x Col 12 Line 4) (12)	Adjusted Kentucky Jurisdictional Capitalization (Col 10 + Col 12) (13)	Adjusted Capital Structure (14)	Annual Cost Rate February 28, 2010 (15)	Cost of Capital (Col 15 x Col 14) (16)
1	Short Term Debt	$ 17,360,542	0.55%	$ (573,676)	$ 16,786,866	0.55%	0.20%	0.00%
2	Long Term Debt	1,440,441,382	45.60%	(47,562,946)	1,392,878,436	45.60%	4.66%	2.12%
3	Common Equity	1,701,046,402	53.85%	(56,168,084)	1,644,878,318	53.85%	11.50%	6.19%
4	Total Capitalization	$ 3,158,848,326	100.00%	$ (104,304,706)	$ 3,054,543,620	100.00%		8.31%

(a) Environmental Compliance Plans

Total Jurisdictional ECR Rate Base at 10/31/09	$ 1,120,801,977
Less Juris ECR Rate Base '01 and '03 Plans	149,293,659
Less Juris ECR Rate Base Roll-In '05 and '06 Plans	867,203,612
Jurisdictional ECR Post '03 Rate Base	$ 104,304,706

NOTES

Column 15 used February 28, 2010 actual embedded cost rates

KENTUCKY UTILITIES COMPANY
ANALYSIS OF THE EMBEDDED COST OF CAPITAL AT
February 28, 2010

LONG-TERM DEBT

	Due	Rate	Principal	Annualized Cost: Interest	Amortized Debt Issuance Expense	Amortized Loss-Reacquired Debt	Letter of Credit and other fees	Total	Embedded Cost
Pollution Control Bonds									
Mercer Co 2000 Series A	05/01/23	0 16000% *	12 900 000	20 640	-	46 7[illegible]	94 413 a	161 796	1 254%
Carroll Co 2002 Series A	02/01/32	0 95000% *	20 930 000	198 835	4 104	36 300	20 930 b	260 169	1 243%
Carroll Co 2002 Series B	02/01/32	0 95000% *	2 400 000	22 800	2 856	4 164	2 400 b	32 220	1 343%
Muhlenberg Co 2002 Series A	02/01/32	0 95000% *	2 400 000	22 800	1 140	12,744	2,400 b	39 084	1 629%
Mercer Co 2002 Series A	02/01/32	0 95000% *	7 400 000	70 300	3,180	12 900	7,400 b	93 780	1 267%
Carroll Co 2002 Series C	10/01/32	0 21200% *	96 000 000	203 520	73,658	186 036	240 000 c	703 214	0 733%
Carroll Co 2004 Series A	10/01/34	0 23000% *	50 000 000	115,000	-	105 023	409 041 d	629 064	1 258%
Carroll Co 2006 Series B	10/01/34	0 29000% *	54 000 000	156 600	47 757	-	441 990 d	646 347	1 197%
Carroll Co 2007 Series A	02/01/26	5 75000% *	17,875 000	1,027 813	33 166	-	-	1,060 979	5 936%
Trimble Co 2007 Series A	03/01/37	6 00000% *	8 927,000	535 620	16,022	-	-	551 642	6 179%
Carroll Co 2008 Series A	02/01/32	0 29000% *	77 947 405	226,047	34,268	-	836 669 d	896,984	1 151%
Called Bonds			-	-	-	200 687 †		200 687	0 000%
Total External Debt			350,779,405	2,599,975	216,151	604,597	1,855,243	5,275,966	0 314%
Notes Payable to Fidelia Corp	11/24/10	4 240%	33,000,000	1,399,200	-	-	-	1,399,200	4 240%
Notes Payable to Fidelia Corp	01/16/12	4 390%	50,000,000	2,195,000	-	-	-	2,195,000	4 390%
Notes Payable to Fidelia Corp	04/30/13	4 550%	100,000,000	4 550,000	-	-	-	4 550,000	4 550%
Notes Payable to Fidelia Corp	08/15/13	5 310%	75,000,000	3,982,500	-	-	-	3,982,500	5 310%
Notes Payable to Fidelia Corp	12/19/14	5 450%	100,000,000	5 450 000	-	-	-	5 450,000	5 450%
Notes Payable to Fidelia Corp	07/08/15	4 735%	50,000 000	2,367 500	-	-	-	2,367 500	4 735%
Notes Payable to Fidelia Corp	12/21/15	5 360%	75,000,000	4,020 000	-	-	-	4 020 000	5 360%
Notes Payable to Fidelia Corp	10/25/16	5 675%	50,000 000	2 837 500	-	-	-	2 837 500	5 675%
Notes Payable to Fidelia Corp	06/20/17	5 980%	50,000 000	2,990 000	-	-	-	2 990 000	5 980%
Notes Payable to Fidelia Corp	07/25/18	6 160%	50 000,000	3,080,000	-	-	-	3 080,000	6 160%
Notes Payable to Fidelia Corp	08/27/18	5 645%	50,000,000	2,822 500	-	-	-	2 822 500	5 645%
Notes Payable to Fidelia Corp	12/17/18	7 035%	75,000,000	5,276,250	-	-	-	5,276,250	7 035%
Notes Payable to Fidelia Corp	10/25/19	5 710%	70 000,000	3,997,000	-	-	-	3 997 000	5 710%
Notes Payable to Fidelia Corp	02/07/22	5 690%	53,000,000	3,015 700	-	-	-	3,015,700	5 690%
Notes Payable to Fidelia Corp	05/22/23	5 850%	75,000,000	4,387,500	-	-	-	4 387,500	5 850%
Notes Payable to Fidelia Corp	09/14/28	5 960%	100,000,000	5,960,000	-	-	-	5,960,000	5 960%
Notes Payable to Fidelia Corp	06/23/36	6 330%	50,000,000	3,165 000	-	-	-	3 165,000	6 330%
Notes Payable to Fidelia Corp	03/30/37	5 860%	75,000,000	4 395,000	-	-	-	4 395 000	5 860%
Notes Payable to Fidelia Corp	04/24/17	5 280%	50,000,000	2,640,000	-	-	-	2,640,000	5 280%
Notes Payable to Fidelia Corp	07/29/19	4 810%	50,000,000	2,405,000	-	-	-	2 405,000	4 810%
Notes Payable to Fidelia Corp	11/25/19	4 445%	50,000,000	2,222,500	-	-	-	2,222,500	4,445%
Total Internal Debt			1,331,000,000	73,158,150	-	-	-	73,158,150	4.350%
		Total	1,681,779,405	75,758,125	216,151	604,597	1,855,243	78,434,116	4.664%

SHORT TERM DEBT

	Rate	Principal	Annualized Cost: Interest	Expense	Loss	Premium	Total	Embedded Cost
Notes Payable to Associated Company	0 200% *	77,898,954	155 798	-	-	-	155 798	0 200%
Total		77,898,954	155,798	-	-	-	155 798	0.200%

	Principal	Interest	Expense	Loss	Premium	Total	Embedded Cost
Embedded Cost of Total Debt	1,759,678,359	75,913,923	216,151	604,597	1,855,243	78,589,914	4.466%

* Composite rate at end of current month

† Series P and R bonds were redeemed in 2003 and 2005, respectively They were not replaced with other bond series. The remaining unamortized expense is being amortized over the remainder of the original lives (due 5/15/07 6/1/25, 6/1/35, and 6/1/36 respectively) of the bonds as loss on reaquired debt

a - Letter of credit fee = (principal bal + 45 days interest)* 70% Rate based on company credit rating Additional fee of $250/month for drawdown
b - Remarketing fee = 10 basis points
c - Remarketing fee = 25 basis points
d - Is a and b combinded

EXHIBIT ____ (LK-22)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2009-00549

UPDATED Response to First Data Request of Commission Staff
Dated January 19, 2010

Updated Response filed March 31, 2010

Question No. 43

Responding Witness: S. Bradford Rives

Q-43. Provide any information, when known, that would have a material effect on net operating income, rate base, or cost of capital that have occurred after the test year but were not incorporated in the filed testimony and exhibits.

A-43. See attached Revised Rives Exhibit 2 and Analysis of the Embedded Cost of Capital, reflecting changes to embedded cost of capital through February 28, 2010.

LOUISVILLE GAS AND ELECTRIC COMPANY

Capitalization at October 31, 2009
with Annual Cost Rate as of February 28, 2010

		Per Books 10-31-09 (1)	Capital Structure (2)	Reacquired Bonds (not retired) (3)	Adjusted Total Company Capitalization (Col 1 + Col 3) (4)	Rate Base Percentage (Exhibit 1 Line 20) (5)	Capitalization (Col 4 x Col 5) (6)	Adjustments to Capitalization (C-19, Pg 2) (7)	Adjusted Capitalization (Col 6 - Col 7) (8)	Adjusted Capital Structure (9)	Annual Cost Rate February 28, 2010 (10)	Cost of Capital (Col 10 x Col 9) (11)
	ELECTRIC											
1	Short Term Debt	$ 150,667,400	6 59%	$ (150,667,400)	$ -	79 62%	$ -	$ -	$	0 00%	0 20%	0 00%
2	Long Term Debt	896,104,000	39 22%	157,937,294	1,054,041,294	79 62%	839,227,678	(6,111,206)	813,116,472	46 14%	4 58%	2 11%
3	Common Equity	1,237,876,536	54 19%	(7,269,894)	1,230,606,643	79 62%	979,809,009	(7,133,714)	972,675,295	53 86%	11 50%	6 19%
4	Total Capitalization	$ 2,284,647,936	100 00%	$ -	$ 2,284,647,936		$ 1,819,036,687	$ (13,244,920)	$ 1,805,791,767	100 00%		8 30%
	GAS											
	Short Term Debt	$ 150,667,400	6 59%	$ (150,667,400)	$ -	20 38%	$ -	$ -	$ -	0 00%	0 20%	0 00%
	Long Term Debt	896,104,000	39 22%	157,937,294	1,054,041,294	20 38%	214,813,616	397,594	215,211,210	46 14%	4 58%	2 11%
	Common Equity	1,237,876,536	54 19%	(7,269,894)	1,230,606,643	20 38%	250,797,634	464,119	251,261,753	53 86%	11 50%	6 19%
	Total Capitalization	$ 2,284,647,936	100 00%	$ -	$ 2,284,647,936		$ 465,611,250	$ 861,713	$ 466,472,963	100.00%		8 30%

NOTES
Column 10 used February 28, 2010 actual embedded cost rates

LOUISVILLE GAS AND ELECTRIC COMPANY

Capitalization at October 31, 2009
with Annual Cost Rate as of February 28, 2010

		Capitalization (Col 6 Pg 1) (1)	Capital Structure (2)	Trimble County Inventories (a) (Col 2 x Col 3 Line 4) (3)	Investments in OVEC and Other (Col 2 x Col 4 Line 4) (4)	JDIC (Col 2 x Col 5 Line 4) (5)	Environmental Compliance Plans (b) (Col 2 x Col 6 Line 4) (6)	Advanced Coal Investment Tax Credit (Col 2 x Col 7 Line 4) (7)	Trimble County Joint Use Assets Transfer (Col 2 x Col 8 Line 4) (8)	Total Adjustments To Capital (9)
ELECTRIC										
1	Short Term Debt	$	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$
2	Long Term Debt	839,727,678	46.14%	(2,295,290)	(279,685)	11,032,725	(2,469,489)	10,223,466	(22,372,933)	(6,111,206)
3	Common Equity	979,809,009	53.86%	(2,679,331)	(326,481)	12,878,687	(2,882,677)	11,934,024	(26,057,936)	(7,133,714)
4	Total Capitalization	$ 1,819,536,687	100.00%	$ (4,974,621)	$ (606,166)	$ 23,911,412	$ (5,352,166)	$ 22,157,491	$ (48,430,869)	$ (13,244,920)
GAS										
1	Short Term Debt	$	0.00%	$	$ -	$ -	$	$	$	$
2	Long Term Debt	214,813,616	46.14%	-	-	397,594	-	-	-	397,594
3	Common Equity	250,797,634	53.86%	-	-	464,119	-	-	-	464,119
4	Total Capitalization	$ 465,611,250	100.00%	$ -	$ -	$ 861,713	$ -	$ -	$ -	$ 861,713

(a) Trimble County Inventories @ October 31, 2009

Stores	$ 4,478,528
Stores Expense	641,802
Coal	14,237,794
Limestone	213,655
Fuel Oil	325,169
Emission Allowances	1,536
Total Trimble County Inventories	$ 19,898,483
Multiplied by Disallowed Portion	25.00%
Trimble County Inv. Disallowed	$ 4,974,621

(b) Environmental Compliance Plans:

Total ECR Rate Base at 10/31/09	$ 240,117,179
Less: ECR Rate Base '01 and '03 Plans	176,206,210
Less: ECR Rate Base Roll-In '05 and '06 Plans	58,558,803
ECR Post '03 Rate Base	$ 5,352,166

LOUISVILLE GAS AND ELECTRIC COMPANY
ANALYSIS OF THE EMBEDDED COST OF CAPITAL AT
February 28, 2010

LONG-TERM DEBT

	Due	Rate	Principal	Interest/(Income)	Annualized Cost: Amortized Debt Issuance Expense	Amortized Loss-Reacquired Debt	Letter of Credit and other fees	Total	Embedded Cost
Pollution Control Bonds									
Jefferson Co 2000 Series A	05/01/27	5 375% *	25 000 000 4	1 343 750	-	117 881	-	1 461 631	5 847%
Trimble Co 2000 Series A	08/01/30	0 240% *	83 335 000	200 004	38,707	143 700	305 611 d	688 022	0 826%
Jefferson Co 2001 Series A	09/01/27	0 275% *	10 104 000	27 786	20 393	-	35 516 d	83 695	0 828%
Jefferson Co 2001 Series A	09/01/26	0 630% *	22 500 000	141 750	9 924	77 424	22 500 b	251 598	1 118%
Trimble Co 2001 Series A	09/01/26	0 630% *	27 500 000	173 250	10,790	65 400	27 500 b	276 940	1 007%
Jefferson Co 2001 Series B	11/01/27	0 750% *	35 000 000	262 500	10 995	49 056	35 000 c	357 551	1 022%
Trimble Co 2001 Series B	11/01/27	0 750% *	35 000 000	262 500	10 997	46 864	35 000 c	357 361	1 021%
Trimble Co 2002 Series A	10/01/32	0 227% *	41 665 000	94 580	37 221	55 812	176 056 d	363,669	0 873%
Louisville Metro 2003 Series A	10/01/33	1 150% 1	128 000 000	1 472 000	-	312 614	127 649 a	1 912 263	1 494%
Louisville Metro 2005 Series A	02/01/35	5 750% *	40 000 000 4	2 300 000	-	96 444	-	2 396 444	5 991%
Trimble Co 2007 Series A	06/01/33	4 600%	60 000 000	2 760 000	47 192	6 567	18 270 a	2 832 029	4 720%
Louisville Metro 2007 Series A	06/01/33	5 625% *	31 000 000 4	1 743 750	-	41 417	-	1 785 167	5 759%
Louisville Metro 2007 Series B	06/01/33	3 200% 3	35 200 000	1 126 400	-	27 328	10 718 a	1 164 446	3 308%
Called Bonds			0	0	-	167,868 2		167,868	0.000%
Total External Debt			574,304,000	11,908,270	186,219	1,210,375	793,820	14,098,684	1.331%
Interest Rate Swaps									
JP Morgan Chase Bank	11/01/20			4 425 831	-	-	-	4 425,831	
Morgan Stanley Capital Services	10/01/33			1 123 782	-	-	-	1 123 782	
Morgan Stanley Capital Services	10/01/33			1.119,942	-	-	-	1,119,942	
Bank of America	10/01/33			1,135,942	-	-	-	1,135,942	
Interest Rate Swaps External Debt				7,805,497	-	-	-	7,805,497	0.737%
Notes Payable to Fidelia Corp	01/16/12	4 330%	25 000 000	1 082 500	-	-	-	1 082 500	4 330%
Notes Payable to Fidelia Corp	04/30/13	4 550%	100,000 000	4 550 000	-	-	-	4 550,000	4 550%
Notes Payable to Fidelia Corp	08/15/13	5 310%	100,000 000	5 310 000	-	-	-	5 310 000	5 310%
Notes Payable to Fidelia Corp	11/23/15	6 480%	50,000 000	3 240 000	-	-	-	3 240 000	6 480%
Notes Payable to Fidelia Corp	07/25/18	6 210%	25,000,000	1 552 500	-	-	-	1 552 500	6 210%
Notes Payable to Fidelia Corp	11/26/22	5 720%	47 000 000	2 688 400	-	-	-	2 688 400	5 720%
Notes Payable to Fidelia Corp	04/13/31	5 930%	68 000,000	4.032 400	-	-	-	4,032 400	5 930%
Notes Payable to Fidelia Corp	04/13/37	5 980%	70,000,000	4.186,000	-	-	-	4.186,000	5.980%
Total Internal Debt			485,000,000	26,641,800	-	-	-	26,641,800	2.515%
		Total	1,059,304,000	46,355,567	186,219	1,210,375	793,820	48,545,981	4.583%

SHORT TERM DEBT

	Maturity	Rate	Principal	Annualized Cost: Interest	Expense	Loss	Premium	Total	Embedded Cost
Notes Payable to Associated Company	NA	0 200% *	129 748,400	259 497	-	-	-	259 497	0 200%
Reacquired Bonds		0 200% *	(163,200,000)	(326,400)	-	-	-	(326,400)	0.200%
		Total	(33,451,600)	(66,903)	-	-	-	(66,903)	0.200%
Embedded Cost of Total Debt			1,025,852,400	46,288,664	186,219	1,210,375	793,820	48,479,078	4.726%

* Composite rate at end of current month

1 Additional interest due to Swap Agreements

Underlying Debt Being Hedged	Notional Amount	Expiration of Swap Agreement	Fixed LG&E Swap Position	Fixed LG&E Swap Position	Variable Counterparty Swap Position
Series Z - PCB	83.335.000	11/01/20	5 495%	5 495%	BMA Index
Series GG - PCB	32 000.000	10/01/33	3 657%	3 657%	68% of 1 mo LIBOR
Series GG - PCB	32 000,000	10/01/33	3 645%	3 645%	68% of 1 mo LIBOR
Series GG - PCB	32.000.000	10/01/33	3 695%	3 695%	68% of 1 mo LIBOR
	179 335 000				

2 Call premium and debt expense is being amortized over the remaining life of bonds due 6/1/15 7/1 13 and 8 1/17

3 Reacquired bonds use expected re-issuance rate

4 Remarketed bonds issued at long term fixed rate

a - Insurance premiums annualized based on actual invoices
b - Remarketing fee = 10 basis points
c - Remarketing fee = 25 basis points
d - Combination of a and c